APA Group

GasNet Access Arrangement Submission (Schedules & Attachments)

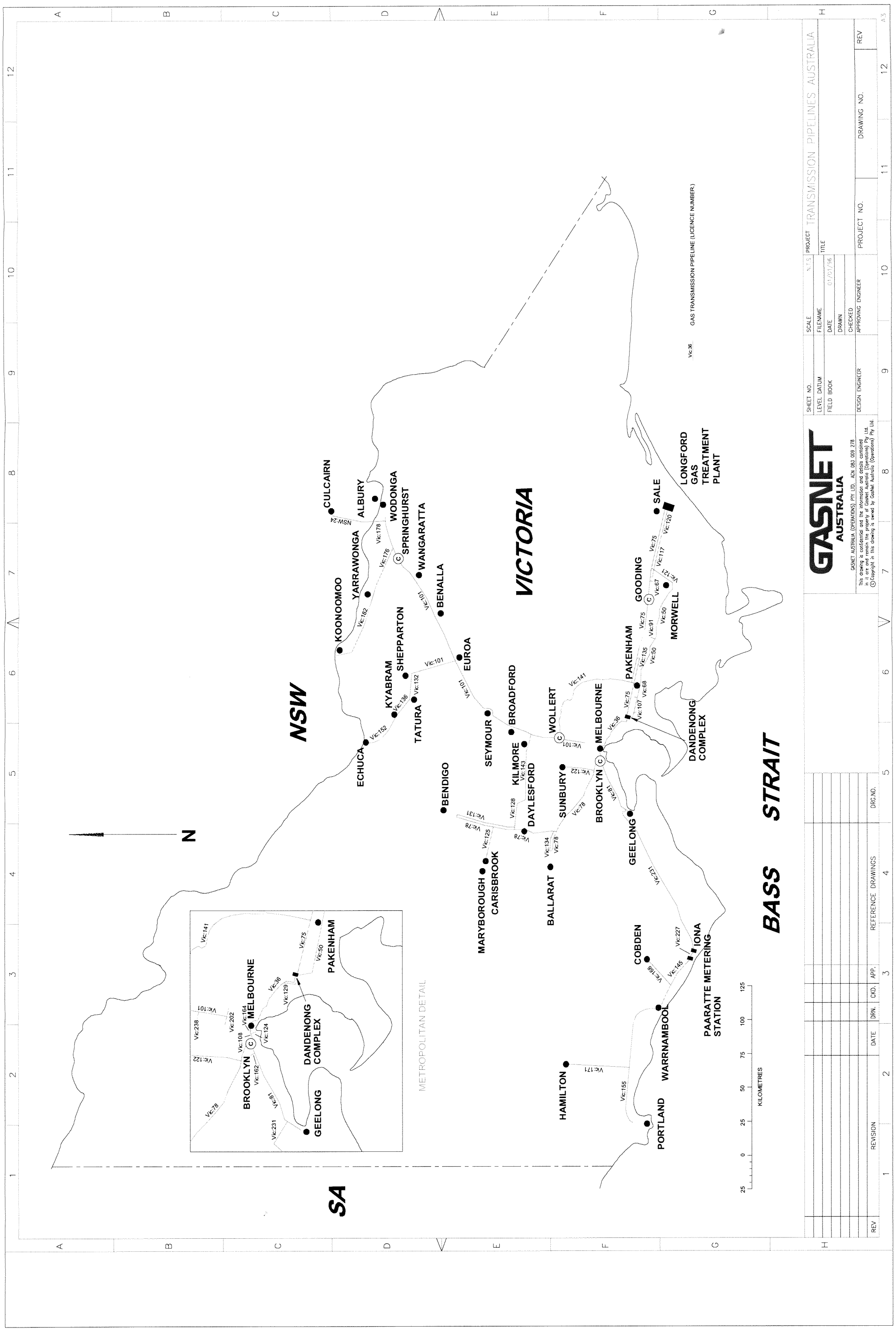
Dated: 22 May 2007

GasNet Access Arrangement Submission (Schedules & Attachments)

Contents

GasNet Access Arrangement Submission (Schedules & Attachments)

Schedule 1 - Map of PTS



1 Ballarat (*Mt Franklin to Ballan Loop*)

The proposed project consists of 40.05km of 300mm NB pipeline (wt 6.4mm Standard Wall and 9.53mm Heavy Wall). Construction will be mainly within the existing easement. There could be some requirement for new easement at isolated locations. For example, the existing pipeline runs for several kilometres within road reserve (Lyman Street) near Daylesford. Sections of the Lyman Street road verges are heavily vegetated and the new pipeline may need to be located within the adjoining private land.

Pig traps and hot taps at Mt Franklin offtake and Ballan bifurcation are required. One midline mainline valve is also required.

Topography is very undulating and hilly (an estimated 1000 trench breakers required). Surface ground conditions reveal poor soil structure and siltstone/sandstone in treed areas. However there is high quality farming soils near Daylesford and Ballan. It is estimated that the proposed route contains approximately 11.1km of rock (Basalt).

A section of right of way easement (of approximately 18km) passes through the Wombat State Forest which contains heavily forested areas either side of the existing easement/cleared right of way. The trees either side will require extensive overhanging branch removal prior to construction.

The environmental management requirements remain unknown until field studies are carried out. Although there is an existing cleared right of way through the heavily forested areas there could be issues with understorey regrowth. As required by the Department of Sustainability and Environment planning provisions, net gain offsets would be required to compensate for removal of native vegetation. This cost could be significant.

Rural living zones abound the easement between KP24.5 to KP27 (approximately). There are potentially two native title groups who will need to be consulted. Dust and noise will require strict control when constructing in these areas.

There are large tracts of Crown land that the pipeline passes through (a proportion of which is used for pine plantations). There are also a number of water crossings. Historic searches will need to be carried out to determine the exposure to native title.

It is not possible to accurately predict the cost of native title in this instance, given the amount of crown land affected.

2 Carisbrook Loop

The proposed project consists of 31.4km of 300mm NB pipeline (wt 6.4mm Standard Wall and 9.53mm Heavy Wall). Construction will be within existing easements.

Pig traps and hot taps are required at Guildford and Carisbrook, and one midline mainline valve is required.

Topography is undulating and hilly for the first 17kms and it is estimated that 200 trench breakers will be required. Surface ground conditions reveal very poor soil structure in the first 17kms with erosion gullies evident up to the start of the basalt plains area. There are very steep escarpments approximately 20m high at Joyce's Creek (KP17.5) and Middle Creek (KP20). It is estimated that the route contains approximately 15.3km of rock (basalt).

Due to potential erosion issues associated with open cutting a number of creeks in the first 15 km, horizontal directional drill construction methodology may need to be investigated and adopted.

The easement passes through cleared farming land with isolated pockets of large trees on the easement. Tree plantations within the existing easement on the section between KP28 and KP31.4 may require removal and re-planting. There are short sections of scrubland in the Daylesford Newstead Road to Captains Gully Road section where work space could be restricted to the existing cleared right of way. The regrowth of young trees and understory on the right of way through these sections may require net gain offsets to compensate for the removal of native vegetation. Until field environmental studies are carried out, this cannot be determined. Minimal environmental issues have been identified to date, apart from construction impact of excavation up steep escarpments at Joyce's Creek (KP17.5) and Middle Creek (KP20) This is because a large portion of the affected land comprises grazing paddocks for sheep and cattle. Further, no homes or industrial premises are impacted.

The new pipeline should be accommodated within the existing easement over the entire route. A small allowance has been made in the event that extra easement is required at water crossings or at the Carisbrook end of line facility.

Temporary work space should be available along most of the route, with the exception of the scrub land areas and some isolated short sections where mature trees are within the right of way.

Exposure to native title cannot be determined until title searching and possibly historic title searching is carried out. It has been assumed that native title will exist, at least over the water courses. GasNet has not dealt with cultural heritage groups in this area previously. The available cultural heritage area maps do not accurately identify boundaries so it has been assumed that there could be two cultural groups.

It is estimated that there will be:

(a) 6 roadway bores;

(b) 17 Open Cut roadways; and

(c) 117 fences crossed.

Access for pipe trucks, equipment and workers would be via the Pyrenees Highway.

3 Warragul Duplication

The proposal consists of the duplication of a section of the Warragul branch pipeline of approximately 4.8 km in length with 150mm pipe.

The existing Warragul pipeline route is a mixture of road reserve and easements through private land. Until meetings with key stakeholders and landholders occur and desktop environmental studies are carried out, it is not possible to provide an accurate estimate for easements and land access.

The existing easement widths, ranging from 2.17 to 7 metres, do not allow for a second pipeline. In some areas where it is not possible to secure more easement (where the pipeline runs between buildings), the new pipeline will be constructed within road reserve. Another section of existing pipeline in road reserve has significant native vegetation and the new pipeline may need to be located within the adjoining private land. Allowance has been made for the acquisition of new easements where it is considered likely to be necessary.

The pipeline route passes through rural zoned land however recent sales have reflected an expectation of this land being rezoned to residential or rural living in the future. The cost of easement acquisition reflects this situation. In addition, an allowance has been made for a panel hearing and compulsory acquisition.

Removal of native vegetation carries with it a requirement for offsets. Until the alignment is chosen and environmental field studies are carried out it is not possible to determine an accurate estimate of the project exposure. In addition, we cannot determine at this stage the manner in which the offsets will be negotiated (eg purchase land, lease, bush broker, etc). Accordingly, an indicative allowance has been made at this stage.

Initial investigations indicate that there will not be an exposure to native title so no allowance has been made. Until title searching of the pipeline route is carried out and the land details referred to Department of Sustainability and Environment's regional native title coordinator there is still some uncertainty.

4 Northern Zone (*Wollert to Wandong*)

The proposed project consists of:

(a) 12.1kms of 450mm NB pipeline (wt 6.7mm Standard Wall, 8.0mm Heavy Wall and 9.7mm Extra Heavy Wall) laid in the existing easement; and

(b) pig traps and hot taps at Wollert and LV 3 and one (1) line valve.

Topography is generally flat along the entire length from Wollert to LV 3. Surface ground conditions reveal basalt plains.

It is estimated that there will be:

(a) a waterway crossing of Merri Creek.

(b) a bored road crossing at Donnybrook Rd of 20m.

It is estimated that 40 fences will be crossed.

The main environmental issues are likely to be the following:

(i) native grassland located in the area; and

(ii) crossings of the Merri Creek which may be opposed by the friends of the Merri Creek given their opposition to a previous pipeline crossing of the creek due to concerns about the impact on the growling grass frog.

There will be a requirement for net gain offsets in relation to native vegetation. An amount has been included for offsets however until environmental field studies are carried out there is no way of accurately determining the exposure.

There is likely to be Crown land along the route that will be subject to native title. A full historical title search needs to be carried out followed by a referral to the regional native title coordinator to conclusively establish whether or not native title exists. An allowance has been made on the assumption that it does exist.

There will be one local aboriginal group dealing with cultural heritage. An allowance has been made for the negotiation of a cultural heritage Management Agreement and for construction monitors.

Access for trucks, equipment and workers would be via existing roadways, as the pipeline extensively parallels the Hume Freeway.

5 Sunbury loop

The proposed project consists of:

(a) 14.93km of 200mm NB pipeline (wt 5.4mm standard wall and 8.18mm heavy wall) in existing easements; and

(b) pig traps and hot taps at the Deer Park offtake and Line Valve 4 on the existing Deer Park Sunbury pipeline (there will be no intermediate main line valves).

Most construction will be in grazing farmland. Topography is generally flat. An allowance has been made for 10 trench breakers. Ground conditions are basalt rock.

It is anticipated that there will be:

(a) Water crossings at Kororoit Creek (open cut as crossing is in basalt); and

(b) road and rail Crossings, with:

  (i) five roads to be bored, including an 80m bore of the Western Highway and a 25 m bore of the Melton Highway;

  (ii) one railway crossing; and

  (iii) six roads to be open cut.

Potential environmental issues are expected to include:

(i) native grass plains located in the area; and

(ii) growling grass frog at Kororoit Creek.

There could be a requirement for net gain offsets so an indicative allowance has been made.

The pipeline will be located within the existing Sunbury pipeline easement however there could be a requirement for extra easement at Kororoit Creek crossing and at the end of line facilities. An allowance for extra easement has been made.

The existing easement is 20 metres wide and allowance has been made to lease a further 10 metres width adjacent to the easement for temporary work space.

A previous historic title search concluded that the only parcel of Crown Land (Kororoit Creek) was once freehold land therefore native title should not exist. We have assumed there will not be a native title requirement. This is subject to final confirmation from the regional native title coordinator.

An allowance has been made for the cost of negotiating a cultural heritage agreement and for monitors during construction.

Access for pipe trucks, equipment and workers would be via existing roadways crossing and parallel to the pipeline (i.e. Hopkins Road).

6 Pakenham South Loop

The proposal involves looping of the 80mm portion of the existing 150/80mm Pakenham Transmission Pressure Pipeline. The project consists of 0.5 km of 150mm NB (wt 6.4mm standard wall) pipeline laid in the road reserve (edge of bitumen) of the Koo Wee Rup Road, adjacent to the existing 80mm pipeline.

No pig traps are required. Hot taps are required at both ends of the pipeline, at the existing 150mm Pakenham Pipeline and at the inlet pipework (100mm) into the existing below ground metering pit.

There are no water or road crossings, or other features that might require bores.

The topography is generally flat. However the work will require full time traffic control during construction, and may be restricted to avoid traffic peak periods. Progress will be slow as no trench is permitted to remain open overnight due to the heavy traffic and the closeness of the trench to the edge of the bitumen roadway.

We have assumed the environmental management requirements will be minimal and confined to issues such as waste management, traffic control, etc. An allowance has been made for an Environment Management Plan to be prepared "in house".

The proposed new License Application fee and License Fee under the Pipelines Act 2005 have been allowed for. Pipelines less than 10 km in length will all attract the same fees.

Access for pipe trucks, equipment and workers will be via existing roadways, as the pipeline is within the Koo Wee Rup Road reserve. There are adequate accommodation options for construction workers in nearby Melbourne suburbs.

GasNet Access Arrangement Submission (Schedules & Attachments)

Attachment A - VENCorp Network Planning and Timing Reports

Reports provided confidentially

GasNet Access Arrangement Submission (Schedules & Attachments)

Attachment B - GasNet Network Report on Carisbrook (Planning and Timing)

NETWORK PLANNING REPORT

CARISBROOK (Planning & Timing)

March 2007

Contents

Executive Summary

The load along the Guildford to Carisbrook pipeline has raised the likelihood of the minimum delivery pressure at Carisbrook being breached during days of high demand. This report assesses the impact of increased demand on the delivery pressures as outlined in the System Security Guidelines and the DB Connection Deeds.

This report also presents a network planning assessment of minimum delivery pressures at the various city gates located on the Guildford to Carisbrook pipeline. Use has been made of historical data, demand forecasts and the Gregg Engineering model of the Principal Transmission System, to predict what year delivery pressures are likely to fall below the minimum pressures as outlined in the System Security Guidelines and DB Connection Deeds.

GasNet's assessment indicates that during winter 2010 a breach in the minimum delivery pressure will occur at the Carisbrook city gate during peak winter demand days.

Investigation into augmentation options has determined that the 150 mm pipeline between Guildford and Carisbrook should be duplicated using 300 mm pipe.

Introduction

The demand along the Guildford to Carisbrook pipeline has raised the probability of shortfalls in gas deliveries occurring at the Carisbrook city gate.

At present, gas flowing to Carisbrook and ultimately the towns of Ararat, Stawell and Horsham can enter from two major junctions:

- Brooklyn - gas from the Inner Ring main and the South West Pipeline enters the Brooklyn to Ballarat pipeline; and
- Wandong - gas from the Wollert to Culcairn pipeline enters the Wandong to Guildford pipeline.

This report presents:

- A historical background of the Guildford to Carisbrook pipeline;
- A review of minimum pressures and flows at Carisbrook for days when lowest delivery pressures occurred at Carisbrook city gate;
- Confirmation of the year in which a 1 in 20 winter peak day delivery pressure at Carisbrook will fall below the minimum level set in the System Security Guidelines and DB Connection Deed, and
- Discussion of the options for augmenting the system to solve the Carisbrook constraint.

Planning Inputs Used

Key inputs used in the modelling are shown in Table 1.

Table 1 Key Inputs into the Modelling

Item	Detail
Forecast Demand data	Supplied by VENCorp and 2006 Gas APR
Historic data	Extracted from VENCorp's TADIS database
Modelling software	Gregg Engineering WinFlow version 4.060503.3081
	Gregg Engineering WinTran version 4.060505.9089
Model of PTS used	Common Model version 2006
GasNet Capex Plan 2008-2012 Version 6	Cost estimation of augmentations produced by GasNet

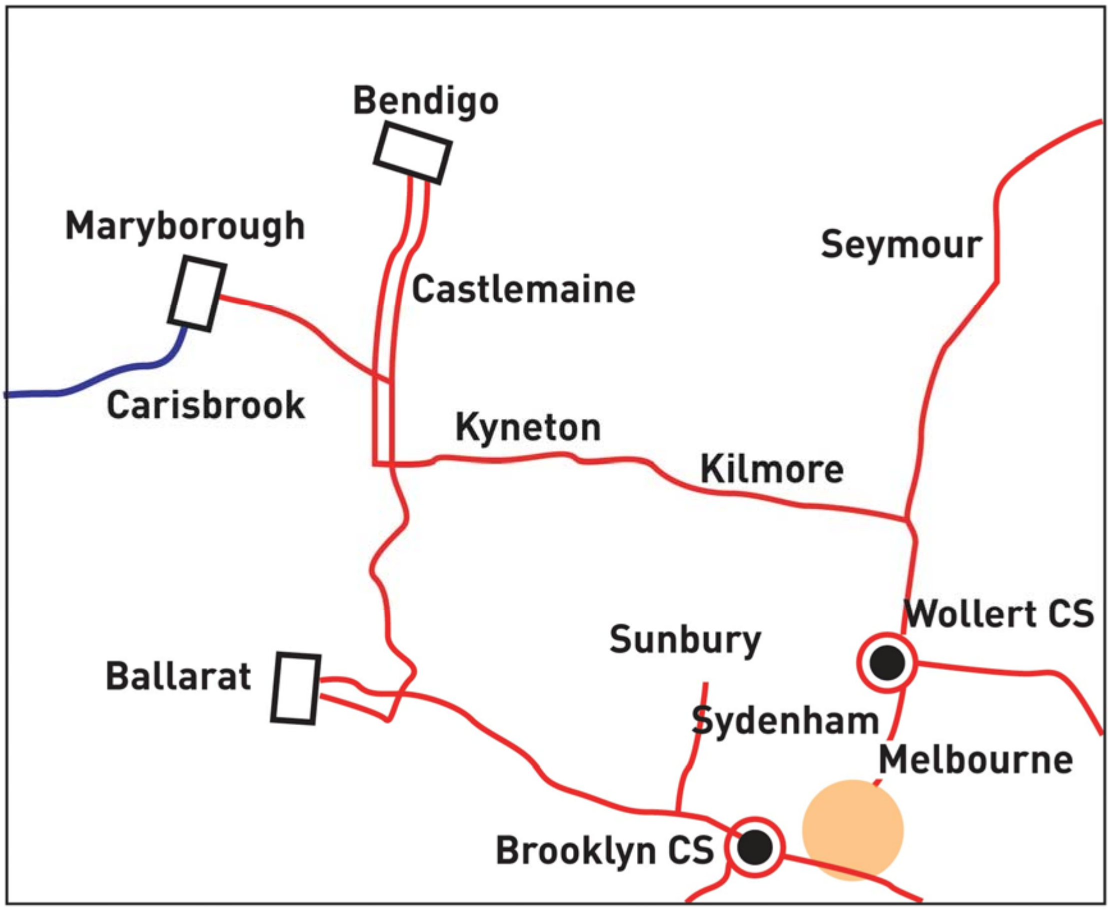


Figure 1 Map of System withdrawal zone and surrounding

Historical Background

In 1973, pipelines were constructed to connect Ballarat and Bendigo to Brooklyn and hence the Melbourne metropolitan transmission system. The pipelines consisted of a 200 mm diameter pipeline from Brooklyn to Ballan and a 150 mm diameter pipeline from Ballan to both Ballarat and Bendigo.

In times of high demand along the PTS, pipeline pressure at Brooklyn was inadequate to maintain minimum pressures at Ballarat and Bendigo. This situation was improved with the flow of compressed gas through the Brooklyn Compressor station into the Brooklyn-Ballan pipeline.

During 1980, the Guildford to Carisbrook/Maryborough pipeline was constructed using 150 mm diameter pipe and is 31.4 km in length.

During 1981, the Mt Franklin to Bendigo pipeline was duplicated using 300 mm diameter pipe to increase Bendigo pressure. In the same year a 300 mm diameter pipeline was constructed from Mt Franklin to Kyneton.

In 1982, the Ballan to Ballarat pipeline was duplicated using 300 mm diameter pipe.

In 1986, a 300 mm diameter pipeline from Kilmore to Kyneton was constructed to link the Bendigo and Ballarat areas to the Wollert to Wodonga pipeline. This allowed high transmission pressure Longford gas to supply Bendigo and part of Ballarat's load in addition to the gas being supplied through Brooklyn. Pressure and security of supply to Ballarat and Bendigo were significantly improved.

During 1996, the Carisbrook pipeline to Ararat, Stawell and Horsham was constructed by Coastal Corporation using 200 mm diameter pipe to Horsham and is 106 km in length with a 100 mm diameter branch pipeline down to Ararat and is 14 km in length. These pipelines are not operated by VENCorp or form part of the PTS but are connected to the Guilford to Carisbrook PTS pipeline at Carisbrook.

It is however worth noting that following the connection of the Carisbrook pipeline in 1996, the pipelines supplying Ballarat, Bendigo and Carisbrook have remained unchanged since 1986.

Due to growth in demand around the transmission system, minimum pressures on laterals around the system tend to fall as demand increases. Reduction in lateral pressures can be offset by increased use of available compressors. This can only continue to be effective while the maximum compressor power has not been reached and/or the compressor discharge pressure is less than the maximum operating pressure of the pipeline.

Forecast Demand

The 1 in 20 winter peak day demand for 2006–2011 was established using forecast data provided by VENCorp to GasNet as part of the Common Model requirements together with the system demand forecasts included in the 2006 GAPR. The forecast demands at Carisbrook and nearby offtakes from the Guildford to Carisbrook pipeline are listed in Table 2 below.

Table 2: VENCorp's 1 in 20 and 1 in 2 Forecast Winter Peak Day Demand (TJ/Day)

Location	2006	2007	2008	2009	2010	2011
Carisbrook (1 in 20)	3.586	3.605	3.628	3.622	3.654	3.674
Carisbrook (1 in 2)	3.581	3.588	3.611	3.603	3.636	3.654
Maryborough (1 in 20)	1.718	1.727	1.738	1.735	1.750	1.760
Maryborough (1 in 2)	1.569	1.572	1.582	1.579	1.593	1.601

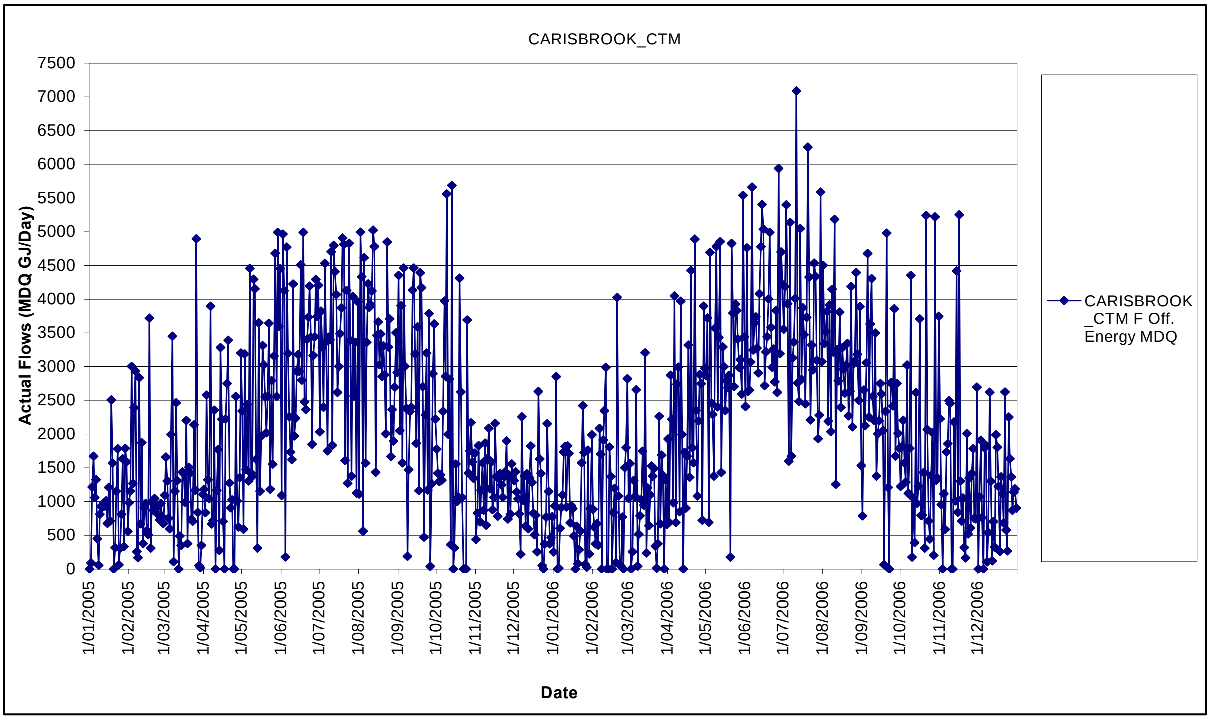


Figure 2: Historical Data: Actual 2005 and 2006 Carisbrook Flows (GJ/day)

It is worth noting that the actual flows experienced to date at Carisbrook (i.e. up to 6 TJ/day) are well in excess of the VENCorp forecast presented in Table 2 above. GasNet modelling is based on the actual flows and the forecast has been adjusted accordingly.

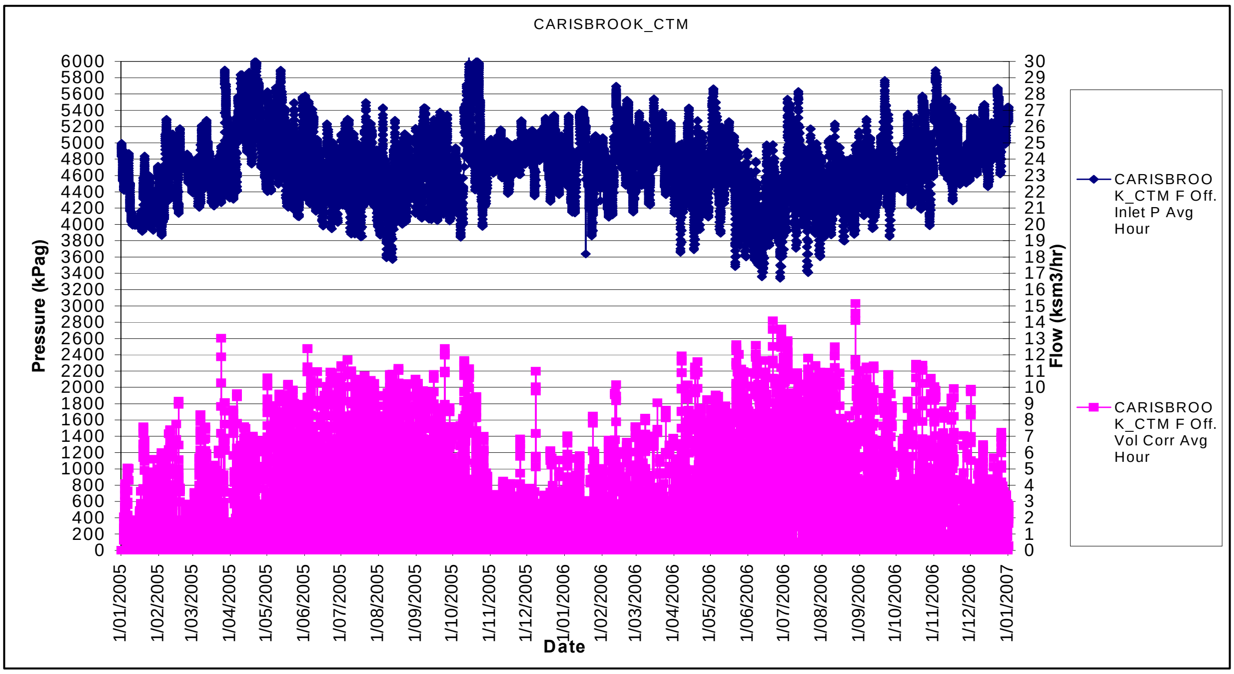


Figure 3: Actual 2005 and 2006 Pressures and Flows

It is worth noting that the actual pressures experienced to date at Carisbrook (i.e. down to 3,300 kPa in 2006) are close to the minimum pressures requirements as presented in Table 3 below. GasNet modelling is based on the actual flows and the forecast has been adjusted accordingly.

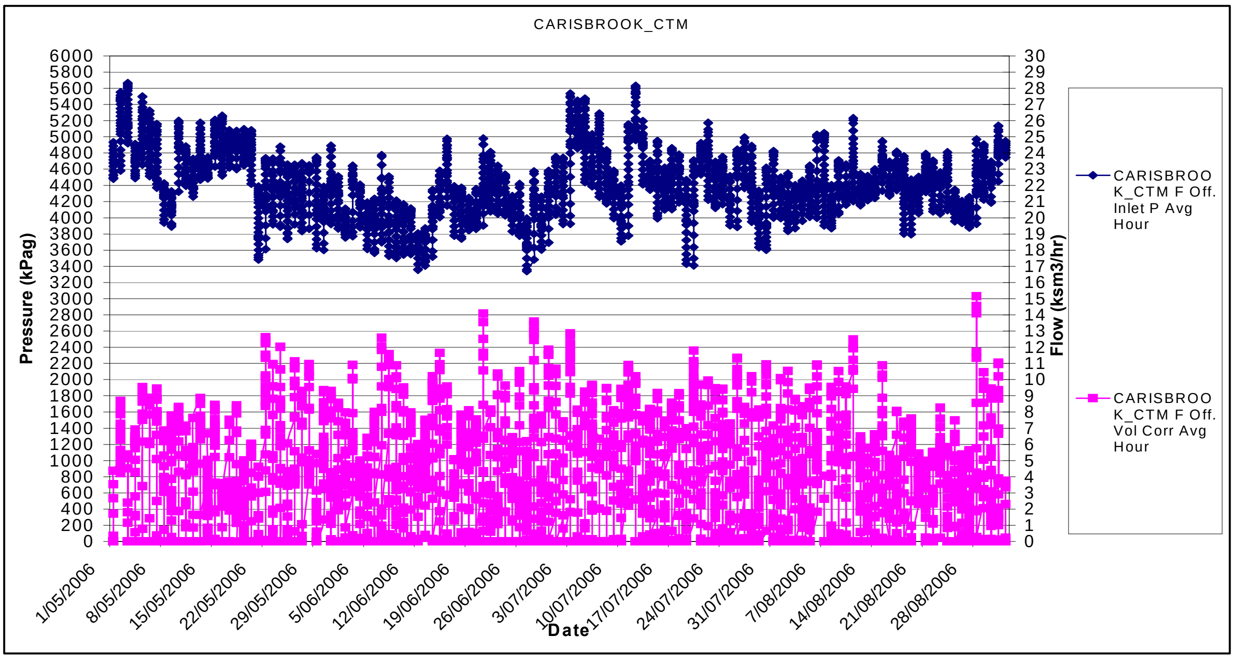


Figure 4: Actual Winter 2006 Pressures and Flows

Forecast Pressures

The forecasting of delivery pressures along the Carisbrook pipeline was conducted by varying the inputs into the Gregg Engineering model of the Carisbrook pipeline, to reflect the growth in demand. The latest Gregg Engineering model was used for the modelling by GasNet.

A summary of the methodology applied to the modelling is as follows:

- forecast demand for all locations as per the VENCorp CTM peak day forecast;
- full availability of transmission assets is assumed with no forced outages.
- Wandong Pressure Limiter is set to 4,500 kPa (required set-point for Culcairn exports – refer to VENCorp's Northern Report and modelling results are linked to this requirement)
- Bendigo/Guildford minimum expected/modelled pressures are 3,500 kPa

The minimum pressure for Carisbrook set in the System Security Guidelines and the DB Connection Deed is 3,000 kPa.

The Gregg Engineering modelling was performed for the period 2007-2011. The results of the modelling shown in Table 3 indicate that a breach of the minimum pressure at Carisbrook is expected to occur in 2010.

Table 3: GasNet's Results - Forecast pressures (kPa) for 1 in 20 and 1 in 2 winter peak day

Location	Minimum pressure SSG /DB Deed (kPa)	2006	2007	2008	2009	2010	2011
Carisbrook (1 in 20)	3,000	3025	3018	3006	3000	2995	2990
Carisbrook (1 in 2)	3,000	3045	3037	3025	3018	3011	3008
Maryborough (1 in 20)	3,000	3030	3022	3011	3005	3000	2995
Maryborough (1 in 2)	3,000	3050	3042	3031	3022	3015	3012

Timing of Augmentation

The augmentation for the Carisbrook constraint is required for winter 2010.

Discussion of the Options

The constraint will cause the pressure at the inlet to Carisbrook city gate to fall to a level that will breach the System Security Guidelines and DB Connection Deed pressure of 3,000 kPa on a 1 in 20 peak day in 2010.

The options available for augmenting the system to solve the Carisbrook constraint are:

a. use of additional compression at Brooklyn and/or Wollert compressor station,
b. use of additional compression at a new Guildford compressor station,
c. duplication of a section of the 200 mm Brooklyn to Ballarat pipeline, or
d. duplication of the 150 mm Guildford to Carisbrook pipeline.

Additional compression at Brooklyn and/or Wollert

As per GasNet's compressor Strategy document, GasNet is currently installing a dry-seal Centaur compressor set (3,500 kW) at Brooklyn, which will be capable of compressing from Melbourne to either Geelong or Ballarat. Scheduled to be commissioned in 2007, the compressor will be used as the primary compressor to Ballarat with the two existing wet seal units available for standby. It has also been proposed in GasNet's Compressor Strategy to progressively retire the existing wet-seal Saturn compressors to prevent injection of oil into the pipeline. Standby dry-seal compression for Ballarat compression service is proposed for 2009.

The modelling assumed the use of 1,700 kW of duty compression at Brooklyn. This is equivalent to the maximum power of the two existing wet seal Saturn compressors or partial day operations of one new dry seal Centaur compressor proposed by GasNet.

Additional compression at Brooklyn is not considered to be the preferred long term option. This is mainly due to the increased risk of compressor failure through regular starting and stopping of compressors on the Ballarat pipeline. The main other issue with this option is the lack of linepack and prevailing pressures as a function of available compression power at Brooklyn to satisfy Carisbrook requirements.

The modelling also assumed the use of 3,400 kW of duty compression at Wollert (refer to VENCorp's Northern Report).

Additional compression at Wollert is not considered to be the preferred long term option. This is mainly due to the increased risk of compressor failure through regular starting and stopping of compressors on the Wollert pipeline. The main other issue with this option is the lack of linepack and prevailing pressures as a function of available compression power at Wollert to satisfy Carisbrook requirements.

New compressor station at Guildford

A new compressor station located at Guildford will solve the Carisbrook constraint. It is expected however that the costs of this station and the ongoing operational costs will be more expensive than a pipeline duplication between Guildford and Carisbrook.

This option is expected to cost $25.0 million.

Duplication of the Brooklyn to Ballarat pipeline

The easement of the Brooklyn to Ballarat pipeline between Brooklyn and Mt Cotterell will be fully utilised by the existing pipeline and the proposed Corio Loop that is to be constructed by winter 2008. A new pipeline in this location would require new easement acquisition. Pipeline duplication west from Mt Cotterell towards Ballarat could use existing easement.

As the Brooklyn to Ballarat pipeline has a diameter of 200 mm, its capacity is twice that of a 150 mm pipeline. If a duplication is performed with a given diameter of pipe, there will be a greater incremental benefit in duplicating a smaller diameter pipeline than a larger diameter pipeline. This is because the pressure loss in a pipeline is proportional to the total cross-sectional area of the pipeline. Therefore, in terms of pipeline duplication, the preferred option is the Guildford to Carisbrook pipeline.

This option is expected to cost $30.4 million.

Duplication of the Guildford to Carisbrook pipeline

Duplication of the 150 mm Guildford to Carisbrook pipeline will solve the Carisbrook constraint and will also add to the security of supply to Carisbrook from the Wollert to Wodonga pipeline.

This option is expected to cost $24.1 million.

Methodology and Modelling Assumptions

The Gregg Engineering software was used to model the PTS to confirm the timing of the constraint and to assess the effect of pipeline duplication in solving the Carisbrook constraint.

The GasNet modelling uses the Gas APR standard approach that applies a simulation over two days. The first day is a 1 in 2 peak day with forecast error such that the EoD linepack is 20 TJ below target. The second day is a 1 in 20 peak day with an initial forecast based on a 1 in 2 peak day that is rescheduled from 1300 hrs to the 1 in 20 peak day demand. LNG is used as required to maintain the pressure at Dandenong.

The modelling used the following assumptions:

- Forecast demand and loads are as per the VENCorp CTM peak day forecast and the Gas APR;
- Beginning of Day (BoD) linepack on target for day two;
- Ideal distribution of linepack over the system;
- No forecast error throughout the day (adjusted in day two);
- No reschedule of gas injections throughout the day;
- Pressure at Culcairn to meet the Culcairn operating agreement with daily average pressure of 3,200 kPa or above (3,000 kPa minimum);
- Pipeline duplication (300 mm) Mt Franklin to Ballan pipeline by winter 2010;
- Flat profiles of export at Culcairn and injections at all injection points;
- Hourly demand profiles for Carisbrook are based on the actual demands recorded during the peak days for 2006;
- There is no load for gas power generators;
- LNG is to be utilised as required to maintain DCG inlet pressure; and
- Full availability of transmission assets is assumed with no forced outages.

Results

The model determined that the minimum pressure at Carisbrook on a 1 in 20 peak day in 2010 would be 2995 kPa. With the 150 mm Guildford to Carisbrook pipeline duplicated in 300 mm, the minimum pressure at Carisbrook would be 3471 kPa.

Results also show the duplication of Guildford to Carisbrook pipeline will reduce the need for operation of the Brooklyn compressors to satisfy the Carisbrook constraint.

Conclusion

From the discussion of the options above, it appears that the duplication of the Guildford to Carisbrook pipeline is the preferred solution to the Carisbrook constraint.

Duplication of the existing 31.4 km of 150 mm Guildford to Carisbrook pipeline in 300 mm pipe solves the Carisbrook constraint for more than 10 years based on the current supply planning basis.

Recommendation

It is recommended that the 31.4 km of 150 mm pipeline between Guildford and the Carisbrook be duplicated in 300 mm pipe prior to winter 2010.

Definitions

BoD - beginning of day, as used in relation to linepack target

DB - Distribution Business, operates a distribution pipeline network

DB Connection Deed - Agreement between VENCorp, Transmission Pipeline Owner and Distribution Business

EoD - end of day, as used in relation to linepack target

Gas APR – Gas Annual Planning Report, published by VENCorp by 30 November each year.

PTS - Principal Transmission System serving Gippsland, Melbourne, Central & Northern Victoria, Albury, the Murray Valley region, Geelong and extending to Port Campbell, owned by GasNet and operated by VENCorp

SSG - System Security Guidelines, developed and maintained by VENCorp for the operation and security of the PTS

SWZ - System Withdrawal Zone

GasNet Access Arrangement Submission (Schedules & Attachments)

Attachment C - GasNet Compressor Strategy

Compressor Strategy

2007 to 2017

March 2007

Contents

1.0 Introduction

This document sets out the compressor strategy to support the Access Arrangement Submission (**Submission**) for the Third Access Arrangement Period. It details the current and proposed operations at the existing compressor station sites at Gooding, Wollert, Springhurst, Brooklyn, Iona, and Boodarie. Details of the facilities and proposed augmentation of the existing five Victorian compressor stations are also presented, along with the compression facilities proposed to be installed at Stonehaven (South Western System) and Euroa (Northern System).

Unless defined in this document, please refer to section 14 of the Submission for definitions and interpretation.

2.0 Description of Existing Facilities

GasNet owns and maintains compressor stations as part of the Service Envelope Agreement (SEA) with VENCorp at Gooding, Brooklyn, Iona, Wollert and Springhurst. VENCorp remotely operate the compressor stations.

Sufficiently large parcels of land surround most of the stations to facilitate expansion, with the exception of Brooklyn facilities which have become badly congested. Brooklyn has a large numbers of compressors, regulators and pipelines in addition to the crowding on the site. Recently a public bicycle track has been installed adjacent to the station vent facilities further exacerbating problems at the site.

Specific features of each compressor station are described below and in Appendix 1, and photos of the sites in Appendix 2. With the exception of Iona, the engines and compressors are all manufactured by Solar Turbines with whom GasNet has a non-exclusive alliance. This alliance provides discounted services, spares and equipment.

2.1 Eastern system - Longford to Melbourne

2.1.1 Gooding

Gooding compressor station is located approximately halfway along the Longford to Dandenong pipeline and compresses gas from Longford into Melbourne. The compressor station was constructed in 1977 and comprised four Solar Centaur T4002-C307 gas turbine driven wet seal centrifugal compressors, any three of which may be operated in parallel to lift the pipeline pressure to a Maximum Allowable Operating Pressure (MAOP) of 6,890 kPa. Each compressor has a nominal output power of 2,850kW. As the station is only required to reach a maximum pressure ratio of 1.35, the outlet temperatures are such that gas cooling systems are not required.

Historically, the station has operated for approximately 80 days per year with a minimum of two and up to three compressors running in winter. Compression is increasingly being used for short periods to relieve high pressure constraints in the Latrobe zone. This trend towards short operation intervals during periods of high inlet pressure is expected to be exacerbated by the recent introduction of the four-hourly gas market.

The four C307 compressors were re-staged in February 1983 when the Longford pipeline was partially duplicated. Subsequent downstream augmentation of the Longford pipeline, (including the commissioning of the Pakenham to Wollert pipeline), and operation of the compressors at high inlet pressure as a result of the competitive gas market have meant that the staging is no longer optimal for current operations.

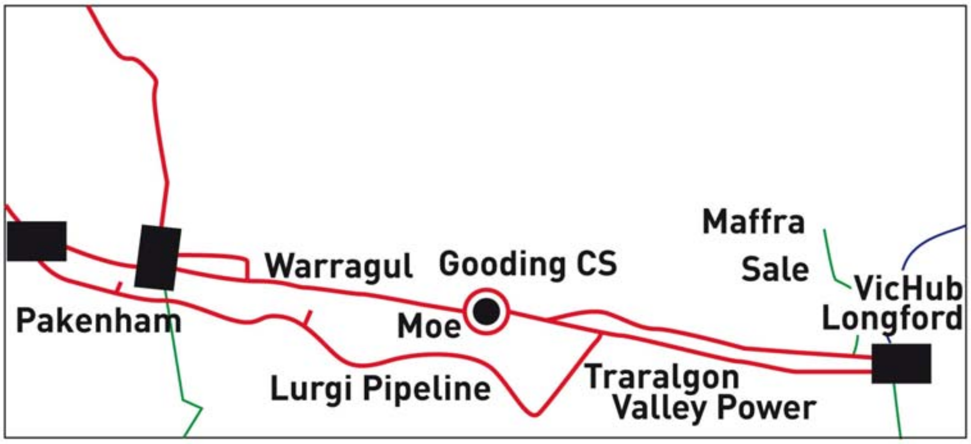


Figure 1 Diagram of the Longford and Lurgi Pipelines

Gooding compressor unit and station control systems were upgraded during 1998. The engines of compressors 1, 2 and 4 were overhauled in 1997 to 1998 and the engine of compressor 3 is budgeted for overhaul in calendar year 2008, subject to condition monitoring (boroscope inspection).

Dry seal C402 compressors are currently being installed to replace the existing C307 wet-seal compressors and provide improved compressor staging. Compressor 4 has been installed and selected facilities have been upgraded including fail-safe station valves, instrument air system, standby generator and fuel gas heaters. Compressors 1, 2 and 3 will be installed in 2007.

2.2 South-Western system - Melbourne to Portland

2.2.1 Brooklyn

Brooklyn compressor station (BCS) is located in western Melbourne and provides gas compression from the Dandenong to Brooklyn pipeline (with a MAOP of 2,760kPa) into the Brooklyn to Geelong and Brooklyn to Ballarat (Figure 2) transmission systems (each with an MAOP of 7,390kPa). As the station operates at pressure ratios of up to 2:1, the station generates high temperatures and the gas is cooled before being delivered into the pipelines. The station is designed to permit a variety of combinations of unit operation including parallel and series operation. The mode of operation is selected using local controls and with units off-line.

Prior to a reconfiguration brought about by the Longford supply incident in September 1998 the station had eight gas driven centrifugal compressor sets in two groups known as Stage 2 and Stage 3 (Stage 1, comprising three reciprocating gas engines, was constructed in 1972 and decommissioned in the early 1980's). Stage 2 was constructed in 1979 with four Solar Saturn T-1200 compressor sets each of 850kW. Two of these units (4 & 5) had been overhauled and upgraded to T1300 units of 950kW in 1997. The original T1200 gas turbines with high running hours from the other two units have been relocated to less critical operations or put in storage.

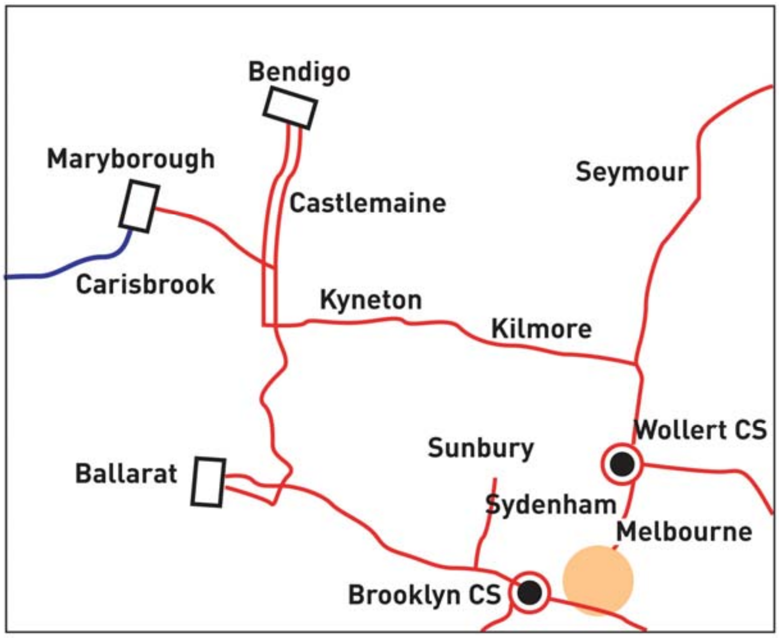


Figure 2 Diagram of the Ballarat Pipeline showing supply from Brooklyn Compressor

Stage 3 was constructed in 1982 with two Solar Saturn T1200 at 850kW (BCS8 and BCS9) and two Solar Centaur T4000 at 2,850kW (BCS10 and BCS11) gas turbine and wet-seal compressor units. The Saturn units in Stage 3 are mainly used to boost pressures into the Ballarat system from the Geelong pipeline and have relatively low running hours. Each unit has its own heat exchanger for gas and oil cooling, but shares water cooling facilities. The Stage 3 building was erected post-construction of the facility in order to provide noise control. The building supports and process equipment (inlet separator and water-cooled gas exchanger) are located immediately adjacent to the equipment, and significantly interfere with maintenance of equipment (refer to photos 10 to 15).

In response to the Longford supply incident in September 1998, VENCorp directed TPA to temporarily relocate Saturn compressors BCS4 & BCS5 to Euroa and Young respectively, to assist with the supply of gas from NSW into Victoria across the Interconnect. Unit 4 remained in place at Euroa through winter 1999 in a temporary facility and was subsequently removed and placed in storage. The engine and compressor of BCS5 were also relocated to Brooklyn where the engine was used to replace the high mileage engine in BCS7. The Saturn T1200 engine from BCS7 was installed at Wollert and the low mileage engine from Wollert installed in BCS6. BCS6 engine was placed in storage, subsequently overhauled and uprated to T1300, and returned to service in WCS2. The original Saturn T1200 engine from BCS7 is now in storage at Wollert. The Saturn T1300 engine from BCS4 has been installed in BCS9 following engine failure in March 2007.

Historically, Geelong demand has been met using Longford gas without compression during the summer months, with some inflow from the Ballarat and Metropolitan systems. Compression was required under the higher loads experienced in autumn, winter and spring, when several Saturn compressors or one Centaur compressor typically operated for extended periods. Peak winter operation required one Centaur and up to three Saturn compressors to meet the Geelong and Ballarat pipeline loads. Centaur compressor unit 11 (C307) was restaged in February 1985 to meet the increasing Geelong system demand. Unit 10 (C306) was restaged in August 1993.

From January 2000, the mode of operation of Brooklyn changed with the connection of the Southwest pipeline (SWP); development of underground storage and ''toll processing' of Santos Otway gas at Iona; and the requirement to refill during the summer months. The Centaur compressors were again restaged and controls upgraded in 1999, and unit 11 engine (Centaur T4000) was overhauled in November 2000. Increasing injections of Otway gas from the Iona UGS and SEAGas systems have resulted in a changed pattern of operation of Brooklyn compressors for much of the year. However, there are typically several weeks of the year where Longford gas is required to flow into the Geelong system and SWP (eg underground storage; gas fired power generation; or refilling the SWP after intra-day linepack withdrawal) using up to two Centaurs, plus compression of Otway or Longford gas using up to two Saturns to Ballarat during periods of high gas demand. This pattern is expected to continue as the gas market moves from daily to four-hourly intervals with an increasing frequency of short-term operation of compressors into the SWP.

In 2006 GasNet commenced a dry-seal compressor retrofit program to mitigate problems being experienced with pipeline liquids affecting customers. The C307 wet-seal compressor of unit 11 was replaced in June 2006 and a new Centaur T4700 compressor package (BCS12) is due to be commissioned in 2007 to replace Centaur package BCS10. Staging in BCS12 has been selected to match the operational requirements for the system following commissioning of the BLP and will be able to compress to Geelong or to Ballarat. The Centaur T4000 engine of unit 10 was overhauled in December 2006.

Significant additional high pressure gas facilities were added to the site with the addition of pig trap assemblies for the Melbourne 750NB, Geelong 350NB and Ballarat 200NB pipelines and the addition of the five-run Brooklyn City Gate and Brooklyn pressure Limiter and associated 500 kW heater installed in conjunction with the SWP in 1998 (refer to photos 16 and 17). The adjacent tip has been closed and a new public bicycle track has been opened on the site boundary adjacent to the station cold gas vent (refer to photo 5). The site will become further congested with four new heaters (700 and 2000 kW), a six-run regulator station and pig-trap for the proposed 10.2 MPa 450NB Brooklyn Lara pipeline (BLP) to be commissioned in 2008. Projections for gas demand in the VENCorp Vision 2030 suggest a further two 450NB and one 600NB 10.2 MPa pipelines and associated pig-traps will be required to terminate at Brooklyn as supply from the Otway basin grows to match the Longford (Bass Strait) system over the next 25 years.

2.2.2 Stonehaven

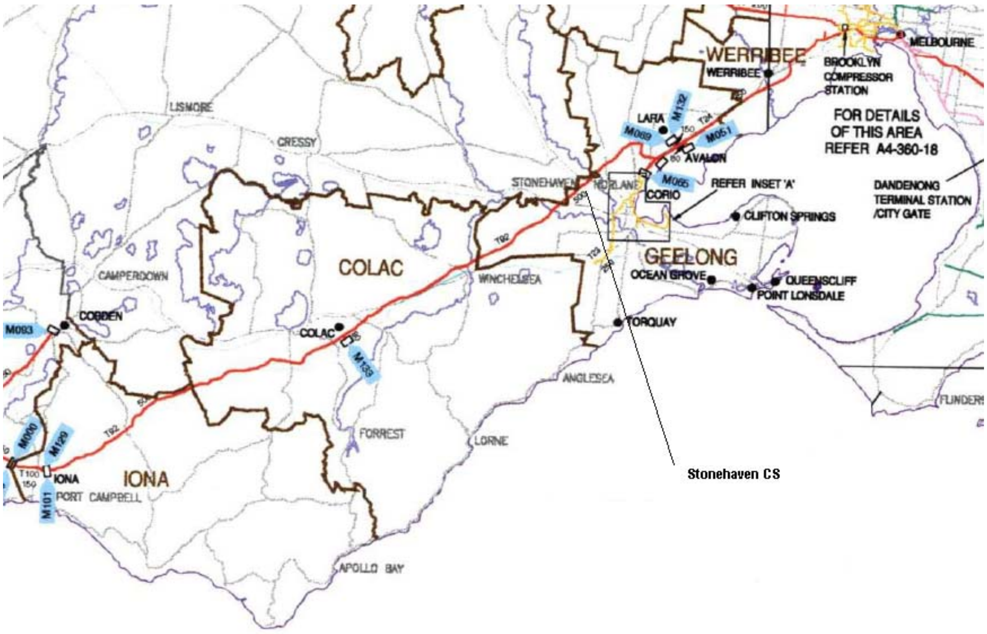


Figure 3 Diagram of the South West Pipeline showing possible location of Stonehaven Compressor

The site of the Stonehaven compressor station is located west from Geelong. GasNet owns property through which the 500mm SWP passes. There is adequate land for initial and projected requirements for the proposed Centaur T6100 compressors. The first Centaur T6100 compressor is projected to be required by 2012.

2.2.3 Iona

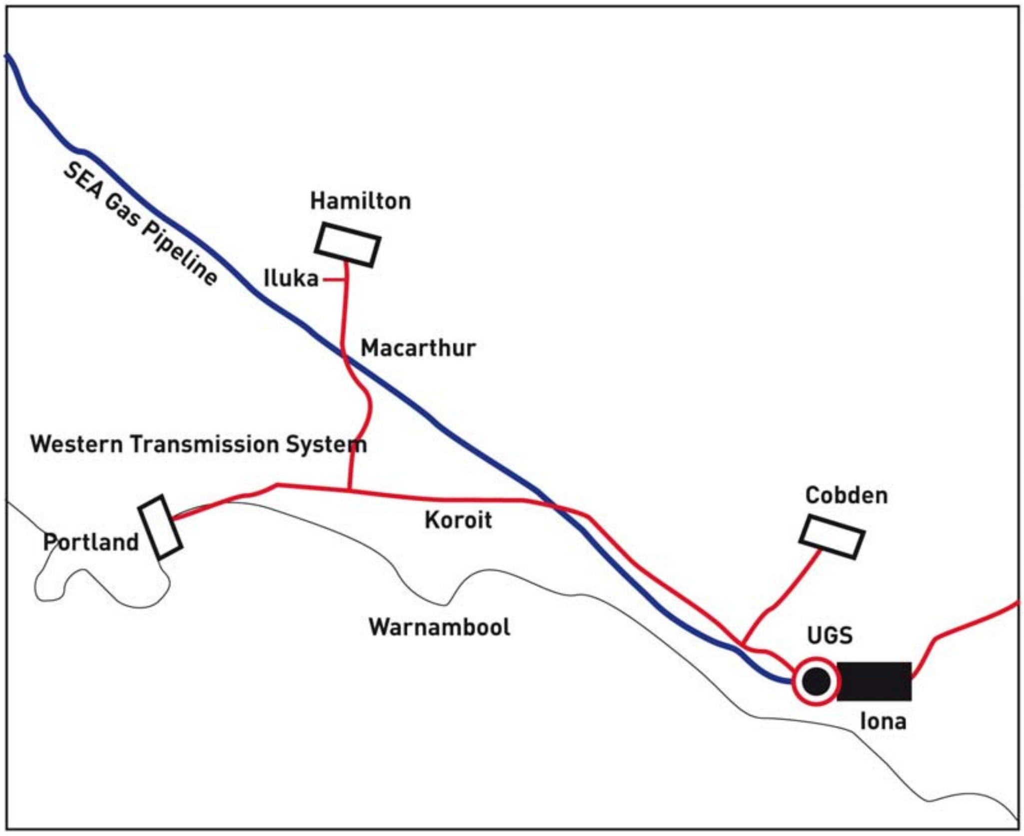


Figure 4 Map of the Western Transmission System

Iona compressor station is located within the Iona Underground Storage Facility (TXUGS) and provides up to 18 TJ/d compression (at inlet pressure 3500 kPa) from the 500mm SWP into the 150mm Western Transmission System (WTS) to Portland (MAOP of 7,400 kPa). Constructed in 2001, the station comprises two gas Caterpillar engine-driven Gemini reciprocating compressor packages with unit cooling designed to meet spring/winter peak demands during underground refill operations, which is an unusual combination of events. Each package provides nominal 300 kW of compression power with one unit a designated backup.

As demands have grown, and in particular with the Iluka connection in 2006, the WTS demand requires higher inlet pressures to the compressors in order to achieve the required flowrates and pressure over the next several years. The VENCorp WTS Planning Report indicates this pressure is achievable with Brooklyn compression and a possible new interconnect to the SEAGas pipeline near MacArthur.

2.3 Northern system - Melbourne to Wodonga/Culcairn

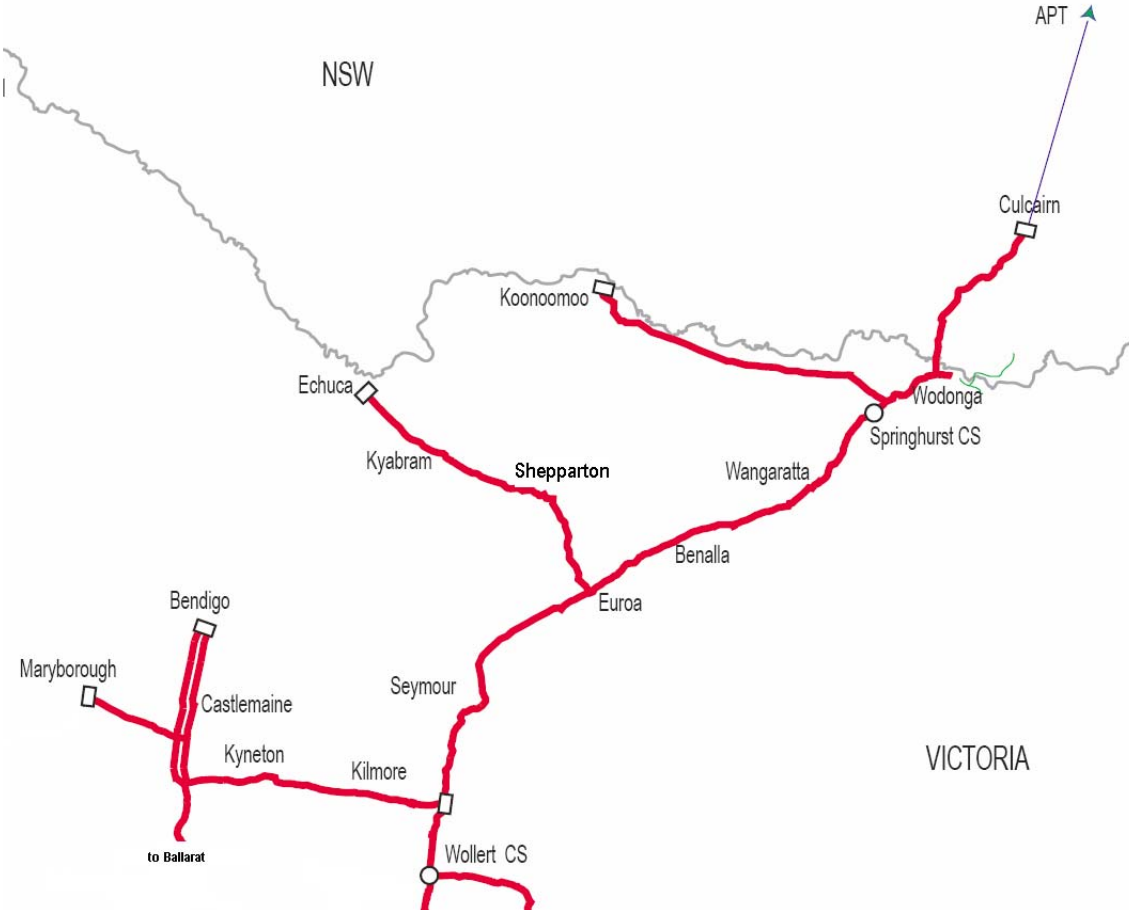


Figure 5 Map of the Northern Zone

2.3.1 Wollert

The Wollert compressor station is located north of Melbourne and is the key supply point for the Wollert to Wodonga transmission systems (MAOP of 7,400 kPa) compressing Longford gas from the outer ring main from Pakenham. The station comprises three Solar Saturn centrifugal compressor sets. The units may only be operated in parallel in any combination from one to three, although one unit is a designated backup.

The station, constructed in 1981, was originally designed to operate with suction from the Metropolitan system. The need for compression from the metropolitan system ceased for a time in 1984 when the Pakenham to Wollert pipeline was constructed. The compressors were restaged before winter 1998 to operate with suction from the Pakenham to Wollert pipeline to meet the expected demand growth in the Wollert to Wodonga system as a result of the commissioning of the Murray Valley and Carisbrook to Horsham pipelines.

The station was not extensively used to support exports into NSW in the period to 2000, so one of its low operating hour engines was swapped for a high operating hour engine from Brooklyn. The Saturn engine in WCS2 was subsequently overhauled and up-rated to T1300 (950 kW) in December 2003. Unit coolers and water towers were decommissioned and replaced with a station fin-fan cooler and station recycle valve in 2005. In recent years, compression has been required with between one and three compressors for 48% of the time (on an hourly basis), with two units operating about 28% of the time. Recent studies (refer to the VENCorp Northern Timing and Planning Reports) have identified that increasing demand in the Northern system has lead to constraints in export capacity at Culcairn, and low pressure at Carisbrook and Echuca.

Detailed designs have been completed for stagewise development of the Wollert site which also addressed some of the identified deficiencies in the current compressor station layout and housing (refer to photos 23 and 24). The revised layout provides for relocation of the station gas headers to the south side of the compressor house, thus removing building and unit air inlets from immediate proximity of the gas releases and providing adequate separation between high pressure gas process equipment and control room main access door. Expansion of the station is proposed to occur to the south of this station header system and provides for new station vents and station valves, but retains the use of the existing control room building.

Current project work has commenced on the automation of the station and in replacing selected facilities including safety system, power supply and distribution systems, backup power generation and master control systems, due for completion in 2007.

2.3.2 Springhurst

Springhurst compressor station, located in the northern section of the Wollert to Wodonga/Culcairn transmission system (MAOP of 7,400 kPa), was constructed in 1999 to support up to 92 TJ/d import of gas from NSW. The station comprises one packaged Centaur (C50) T-6102 centrifugal compressor set at 4500 kW. Although the station is only currently capable of compression south, bi-directional compression is possible with minor pipework and valving alterations.

The VENCorp Planning Report on the Northern Zone constraints has identified possible augmentation of compression (possibly with Saturn compressor), reversal of flow and/or looping of pipework between the station and Interconnect at Barnawartha. In conjunction with augmentation of Wollert compressor station (for an increase in power to 3400kW), this has been assessed among other options including Wollert-Wodonga partial pipeline looping and compression at Euroa. These options are discussed below.

3.0 System Growth Outlook

VENCorp have published the following documents which provide information on system growth outlook and current operating practices:

- Vision 2030;
- Gas Annual Planning Report 2006;
- Gas Scheduling and System Operations over Winter 2006; and
- System Augmentation Report 2005, Lara to Brooklyn.

Other planning and timing reports have been prepared in relation to each identified constraint in the network. These are being managed under the Network Development Working Group comprising representatives from VENCorp and GasNet. VENCorp has prepared Timing and Planning Reports for:

- Ballarat;
- Sunbury;
- Northern Zone (Echuca, Carisbrook and Culcairn exports);
- Western Transmission System;
- Warragul;
- Pakenham; and
- SWP (Stonehaven).

The system augmentations outlined below are premised on increasing supply capacity (injections) from the Otway systems (UGS, Casino, Minerva, Geographe, Thylacine etc) with only modest changes to the supply from Northern and Eastern systems until Otway gas reaches in the order of 600 TJ/d.

3.1 Eastern system - Longford to Melbourne

The capacity of the Longford to Dandenong/Wollert system is 990 TJ/d utilising three compressors at Gooding and the Lurgi pipeline. The Longford VicHub facility is able to inject 135 TJ/d of gas including new gas from the OMV Orbost gas plant. The Origin BassGas facility commissioned in 2006 is able to inject 67 TJ/d of new gas from the Yolla gas field connecting at Pakenham.

VENCorp have recently indicated that operational end-of-day (EoD) pressure at Longford is 6500 kPag, which provides some ‘‘head room’’ for potential forecast error resulting in higher pressures which have the potential to reduce flows in the Esso Longford process and offshore facilities. The Esso deliverability is reduced at pressures exceeding 6750 kPag.

No system capacity augmentation is proposed for the Third Access Arrangement Period.

3.2 Northern system - Melbourne to Wodonga/Culcairn

The capacity of the northern system is 50 TJ/d south through Culcairn utilising the compressor at Springhurst (note: 92 TJ/d utilising both Young and Springhurst), and 17 TJ/d north through Culcairn using up to two Saturn compressors at Wollert.

The Planning Report for the Northern Zone (Euroa and Carisbrook constraints), identifies the immediate need for:

- an increase in Wollert compression power;
- partial duplication of the Wollert to Wodonga pipeline; and
- an upgrade of the Springhurst compressor station or installation of a new compressor station at Euroa.

3.3 South-Western system - Melbourne to Portland

The capacity of the South-western system is nominally 50 TJ/d into TXUGS at Iona using two Centaur T4002 compressors at Brooklyn at less than 7.4 Mpa.[1] The capacity of the South-western system is nominally 220 TJ/d at 10 MPa from Iona to Melbourne. The bi-directional SEAGas facility at Iona will also introduce up to 200 TJ/d injection of new gas from Minerva or 135 TJ/d withdrawal to Adelaide in event of Minerva plant failure. Prospective new gas from the offshore Geographe and Thylacine fields has been committed with the new BHP facilities at Iona currently under construction.

Augmentation of the Brooklyn to Iona sector with compression at Stonehaven and duplication of the Brooklyn to Lara pipeline can increase westerly capacity to nominally 110 TJ/d and easterly flow to 415 TJ/d. To reach maximum capacity, the pipeline will need to operate at 10 MPa between Iona and Brooklyn. A site for the Stonehaven compressor station has been chosen and agreement reached with the land owner subject to obtaining a planning permit from the local council. The Stonehaven station is not expected to be required before 2012 (refer to VENCorp timing report).

The capacity of the 150mm western system to Portland is 19 TJ/d at an inlet pressure of 3800 kPaG using one compressor at Iona, discharging at 5600 kPaG. The capacity of the 150mm western system to Portland is 25 TJ/d at an inlet pressure of 4800 kPaG using one compressor at Iona, discharging at 6350 kPaG.

The gas processing facilities at Nth Paaratte have been de-commissioned so that currently Iona (UGS and SEAGas) and Longford gas via compression at Brooklyn are the only sources of gas supply into this system. Augmentation of the western system could also be achieved with connection to the SEAGas pipeline south of Hamilton.

3.4 Intra-day Balancing and Eastern System Constraint Management

VENCorp operating practice on the SWP over winter 2006 has been to achieve about 7000 kPag EoD (0900 hrs) pressure at Iona on most days, giving a system-wide active linepack total of 280 TJ, and allowing up to 30 TJ of active linepack subject to adequate Otway gas injections overnight. This corresponds to daily typical pressures at Iona from 5000 to 8000 kPa depending on timing of operation of Lara CG and injection quantity at Iona (1000 kPa in the SWP corresponds to about 10 TJ of linepack).[2] This EoD target is unsustainable when Otway gas injections are unavailable (eg during UGS maintenance shutdown or during low demand periods when market schedules Otway gas off), and during periods of high demand on the Geelong system when Longford gas is required to be delivered using compression at Brooklyn.

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[1] Two Centaur T4002 compressors have insufficient power to achieve 7.4 MPa. Capacity to transport to UGS is limited if Geelong system demand is above 40 TJ/d.

[2] Gas Scheduling and System Operations over Winter 2006 and System Augmentation Report 2005, Lara to Brooklyn

Re-bidding processes in the event of a reduction in demand (eg weather forecast error leading to a reduction in required injections) generally leads to reduction of injections from higher priced gas (typically Otway gas), which in turn creates the potential for a high pressure constraint in the Eastern System. This is managed by VENCorp by moving Longford gas into the SWP using compression at Gooding and Brooklyn, and gas into the Northern System using compressors at Wollert. The small diameter pipelines at compressor outlets at Wollert and Brooklyn, compression staging and power limit the quantities that can be effectively moved overnight, although the quantity of active linepack available is expected to increase with the installation of the SWP into Brooklyn[3] by winter 2008 and Wollert to Wandong pipeline[4] by 2009.

Current maximum discharge pressure from BCS10 and BCS11S operating together into the Corio pipeline is about 6200 kPa, and into the SWP at Lara is about 6000 kPag, a slight increase due to the replacement of BCS11 with a dry-seal compressor which removed the 'P2 delta P' constraint.

Following commissioning of the T4700-C336 BCS12 compressor at Brooklyn by winter 2007, the flows and pressure will marginally increase with operation of BCS11S with BCS12, and again by winter 2008 when SWP is extended into Brooklyn.

This strategy also proposes that additional compression and connections be provided which permit compression in two stages: BCS11P from Melbourne to Geelong header; and BCS12 from Geelong header into the SWP. This greatly increases both the pressure and flowrates which are able to be delivered to manage intraday balancing and Eastern System gas constraints. This also significantly breaks the dependence on Otway gas injections overnight to achieve EoD linepack target, providing access to the 30TJ+ linepack reserve in SWP at any time.

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3 System Augmentation Report 2005, Lara to Brooklyn

4 VENCorp Northern Planning Report

4.0 Compressor Major Upgrade Strategy

4.1 Gooding Compressor Station

In the Access Arrangement for the Second Access Arrangement Period, an upgrade to the facilities at the Gooding compressor station was approved by the ACCC. The reason these assets needed to be upgraded was because of their age and generally poor condition. This work is in the process of being undertaken. The details of this work are outlined below.

Gooding C307 wet-seal compressors are currently being replaced with new C402 dry seal compressors that will also deliver staging that better suits operational requirements. Unit 4 is complete (2007) with the balance to be completed by the end of 2007. Other works included in the approved scope of works includes the following:

- instrument air system (complete 2007);
- station isolation valves have been upgraded to class 600 with fail-closed actuators (complete 2007);
- faulty unit 4 isolation valves have been replaced (at this stage retaining the fail-last actuators);
- backup generator (complete 2006);
- fuel gas heaters (complete 2006);
- discharge silencers (complete 2006); and
- air inlet filters (complete 2006).

The operation of compressors at very high inlet pressures requires additional work to protect the dry-seals from damage. This work is planned to be completed in 2007.

- Seal gas filtration and booster systems

Whilst undertaking a review of its compressors stations GasNet identified a deficiency in it firefighting capability at Gooding. Therefore as part of the Access Arrangement Submission for the Third Access Arrangement Period, GasNet is proposing to install firefighting equipment at a number of compressors stations including Gooding. This is necessary at Gooding because all compressors are located in a common compressor hall and are also exposed to possible loss from fire due to the risk of fire from failure of oil hoses (etc). The lack of fire suppression systems means that a fire can knock on to adjacent units. Implementation of a Marioff Hi-Fog suppression system is proposed for 2008 at an estimated cost of $990.

The projected gas flow demands for the medium term are not projected to increase, so no planned increase in engine power is foreseen at this stage. However, it is expected that GCS3 (which is the only engine to have not been overhauled), is likely to need an overhaul because of age related performance issues with an exchange T4500 engine for the Third Access Arrangement Period.

4.2 Brooklyn Compressor Station

The Brooklyn compressor station has been designed to provide compression to re-fill the Underground Storage facility (UGS) and potentially provide supply to the Western System, as well as compressing into the Geelong and Ballarat/Bendigo systems under standard mode. UGS can supply up to 200TJ/day during winter and refill capacity up to 50TJ/day for 200 days during summer and shoulder periods. It is anticipated that total injections from UGS and SEAGas at Iona up to the capacity of 307 TJ/d on the SWP and BLP to Brooklyn will be achievable by winter 2008.

Centaur compressors 10 and 11 have been restaged, and the heat exchangers replaced. This restaging gave compressors 10 and 11 (in series mode) higher head capabilities to meet UGS needs. For UGS refill, both BCS11 and BCS12 may be required to operate, and BCS10 will be available for back-up until the completion of the proposed station upgrade.

History and modelling indicates that when there are adequate injections at Iona, the need for compression out of Brooklyn is minimal. However, periodic shutdowns of UGS facilities and low injections from SEAGas have meant that compression from Brooklyn has been necessary to meet demand in the Geelong and SWP/WTS systems for several weeks each year. Two Centaurs have been used extensively in the first several months of 2007 to meet the combined Geelong/SWP demand including gas-fired power generators (GPG) at Laverton.

After installation of BCS12, it will be BCS11 (in parallel mode) that will meet the standard mode operation with BCS12 (or BCS10) providing back-up. If Laverton GPG is required to operate, both BCS11 and BCS12 will be required to operate to Geelong. BCS12 will normally be available to operate as the preferred compressor to Ballarat with the Saturn wet-seal compressors as back-up until completion of the proposed upgrade, at which time BCS13 will be available as backup.

4.2.1 Brooklyn Compressor Package Upgrades

Whilst maintenance support from Solar Turbines Australia is still available, the relay-based unit control systems on the Saturn compressor sets (BCS 6, 7, 8 and 9), the Saturn 10 (T1200) turbine engines and C168 compressors are all outdated technology.[5] Renovation or upgrade of gas compressor packages is costly and in practice on-site upgrades are limited to up-rate of engines from T1200 to T1300 (nominal 1300hp = 950kW).

The engines on BCS4 and BCS 5 were up-rated from T1200 to T1300 in January 1998 having each achieved over 35,000 hrs. However, the compressor packages and balance of plant were removed from service in September 1998 (as a result of the Longford incident) and the engines have been installed into BCS9 and BCS7 respectively.

BCS10 Centaur engine was overhauled in 2006. However, the wet seal C306 compressor cannot be upgraded on the integral skid. Balance of plant (valves; control valves; inlet separator; gas and oil coolers; water cooler; and piping) remains as originally installed in 1982 and can pump only from Melbourne into the Geelong pipeline. The reasons for the replacement of BCS10 are gone into more detail in section 4.2.3 (Stage 1: BCS12. (2006/2007)) below.

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5 The relay-based control logic used in the Solar Saturn compressor used at Brooklyn and Wollert (Photo 25) limits opportunities for safety improvements and rapid maintenance diagnostics and repair. For example, recent corroded 'fail-last' actuators at Brooklyn are more cost effective to replace than repair. However, suppliers have been required to remove the spring from stock items in order to permit them to function in the existing Saturn control system. The 'spring-to-close' characteristic for isolation valves is preferred from a safety perspective and therefore Good Practice – see later discussion.

BCS11 Centaur engine was replaced with an overhaul exchange engine in 1996 (a T4500 de-rated to T4000) and the C307 series/parallel compressor was replaced with a dry-seal C337 series-parallel compressor. Balance of plant (valves, control valves, inlet separator, gas and oil coolers, water cooler, and piping) remains as originally installed in 1982 and can also pump only from Melbourne into the Geelong pipeline.

A new Centaur compressor package (BCS12) using a T4700 Centaur engine and C336 dry-seal compressor is proposed to be installed by winter 2007. The new compressor package, to be housed in the Stage 1 building, will be designed with new balance of plant and to current engineering design practices (fail-safe valves, safe area controls etc). BCS12 is proposed to be capable of pumping from Melbourne to either Geelong or Ballarat, thus allowing the Saturn wet-seal compressors to assume back-up function until completion of the upgrade programs outlined below.

4.2.2 Station Redevelopment

The following proposed strategy for re-development of the Brooklyn Compressor Station is set in the context of current requirements for upgrade of existing assets due to design and support deficiencies (including removing wet-seal compressors in order to cease injections of oil into the pipeline in accordance with the directive from Energy Safe Victoria[6]), and the projected augmentation program to meet short and medium term growth in demand. The current BLP project will connect to the Geelong pipeline via the proposed BLP City Gate facility to allow gas to be compressed westwards into the SWP utilizing both the Geelong and SWP pipelines at pressures up to 7390 kPa. Although gas supply from the Otway system is projected to increase in coming years, leading to decreased utilization of compression plant into Geelong, the need for capability to move Longford gas into both Geelong and Ballarat systems and for refill of the UGS at Iona is expected to continue. The following strategy sets out the steps necessary to move from the current station set-up to a four-Centaur compressor station at Brooklyn capable of compression into Corio, Ballan or SWP pipelines. Based on current modelling, the four-Centaur compressor station is the most efficient means to meet the requirements of the gas network going forward.

Vital equipment is exposed to possible loss from fire due to the potential of fire from failure of oil hoses etc (GasNet has experienced two oil fires on this site, and the Australian gas pipeline industry more broadly has experienced some major losses as the result of fires). In the absence of fire suppression equipment, a fire once started can knock on to adjacent units very easily and quickly. Implementation of a Marioff Hi-Fog suppression system on Centaur package for unit 11 is proposed for implementation by the end of 2008 at an estimated cost of $135k.

Equivalent suppression systems for the existing Saturn packages is $540k which would be avoided under the proposed program. Costs of installing fire suppression for the proposed equipment is included in the costs presented below.

Fuel gas heating and filtration will have to be installed as Otway gas is typically close to the hydrocarbon dewpoint specification limit and is required to maintain Solar Turbines warrantee for new packages[7]. Estimated cost for the fuel gas treatment system is $600k.

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6 Energy Safe Victoria letter to CEO, GasNet Australia Pty Ltd dated 27th March 2006

7 Solar Turbines Specification ES9-98 Fuel, Air and Water (or Steam) for Solar Gas Turbine Engines

4.2.3 Stage 1: BCS12. (2006/2007)

The existing 25-year old Centaur BCS10 has an integral engine/compressor skid and cannot be upgraded to provide dry-gas seals. Moreover, this equipment has a number of design deficiencies that bear on the safety, operability and reliability of the plant, including:

- 'fail-last' valves;[8]
- swing-check non-return (NRV) valves;[9]
- air intakes from the process gas side of the building;[10] and
- water-cooling[11] equipment with associated Legionella[12] and process equipment failure[13] risks.

Whilst the equipment is packaged, there is no fire suppression system and the potential for oil fires remains. GasNet have experienced several incidents in recent years including failure of unit isolation valves, process gas coolers, swing-check NRV valves[14] and oil fires. The frequency and severity of these incidents has the potential to grow due to the age of the facilities and the increasing congestion of the site. The Stage 3 compressor building is in a poor state of repair, interferes with maintenance access (refer to photos 10 to 15, 18 & 19), and is located immediately adjacent to the high pressure Brooklyn City Gate heating and pressure regulating facilities (refer to Photos 16 and 17). There are several more pipelines proposed to terminate within this site within the next several years, so that potential for knock-on effects from significant fire events (jet-fires etc) will increase in both severity and probability. Consequently, this strategy proposes to ultimately decommission and demolish all Stage 3 facilities, including the aged BCS10 compressor and all associated balance of plant.

The BCS12 project involves the installation of a Centaur (40) T4700-C336 gas compressor package into Stage 1 building. This package has the current equivalent capability of the BCS10 compressor, although it has marginally higher power (3500 kW, up from 2850 kW) and has a

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8 In event of loss of 24 Vdc or fire/explosion, 'fail-last' valves will fail into the last operating position, potentially providing high pressure source of gas from the pipeline into the compressor building and consequent escalation of hazards. Failure of an isolating valve to close has been known to result in total loss of pipeline compressor station (refer Princess Compressor Station in Canada). Good engineering practice is to provide 'fail-safe' valves which will isolate and vent process equipment in event of detected hazard or loss of control.

9 Swing-check valves are used to prevent backflow of high pressure gas from the discharge piping from flowing backwards through the compressor to the suction piping (see Appendix 1). GasNet has recorded a number of failures of these components due to the severe service conditions resulting in damage to both compressors and engines. The preferred design for this application is known as an axial non-return valve.

10 Ingestion of gas from a gas leak from process equipment into a contained space such as a compressor building may result in explosion, whereas unconfined vapour cloud explosions have not been recorded for natural gas. Operating gas turbine equipment has surfaces hot enough to ignite gas. The preferred risk minimisation strategy is separation of air intakes from potential sources of gas release.

11 Potable water consumption from the air cooling towers was about 56,000 litres per day for the first three months of 2007 operating two Centaur compressor packages part-time (5 Megalitres for the quarter).

12 Legionella has been detected in Brooklyn water cooling systems. Whilst operational controls are in place, the potential exists for exposure to operations personnel and the public who are exposed to overspray. Good practice in the pipeline industry is to use fin-fan coolers which do not use water and minimise corrosion.

13 Corrosion of high pressure water-cooled exchangers has resulted in several recorded instances of leakage in equipment, the most severe of which lead to spillage of oil and oily water, damage to gas turbine engines due to water ingress into the compressor and engine oil tank, and emissions of natural gas to atmosphere.

14 Appendix 1 lists a number of repairs to compressors and engines resulting from swing-check non-return valve failure

slightly improved thermal efficiency. The opportunity has been taken to optimise the compressor staging for current and forecast service conditions, including capability to compress to Ballarat, and potential to compress into the Brooklyn Lara Pipeline from the Geelong pipeline. The package has the following key features:

- standard Solar enclosure;
- TT4000 controls (including Windows HMI);
- fire and gas detection with Marioff HiFog fire suppression;
- electric start;
- dry gas seal compressors; and
- interface to GasNet SCADA LAN (enables remote support).

Balance of plant includes the following:

- fail-safe process valves utilizing instrument air;
- outlet connections to Geelong and Ballarat pipelines;
- anti-surge valve utilizing instrument air;
- axial type unit non-return valves;
- inlet filter-coalescer;
- fin-fan process gas cooler; and
- fin-fan lube oil cooler.

Station facilities required include the following:

- vent gas monitoring; and
- modifications to station cold gas vent.

The design intent during the construction period is to minimise disruption to station core operations.

Until Stage 1 is complete, the Centaur units and Stage 2 building will continue to be exposed to potential risk of gas ingestion should there be a significant gas release near the compressor house. Once complete, BCS12 will be available as the lead machine for compression to Ballarat, thus allowing the Saturns to be relegated to standby status. Similarly, BCS12 will be available for compression to Geelong in parallel with BCS11 with BCS10 relegated to standby status (if concurrent compression to Geelong and Ballarat is required, the Saturns would be used to Ballarat).[15] With the low hours of expected use of the standby units, the risk of loss through fire or gas release is significantly reduced.

At the conclusion of Stage 1 implementation, the reliability of station controls will have improved and remote support improved. BCS12 will be available to operate in parallel with BCS11 (series mode) compressing into Geelong or alternatively compressing gas into the Ballarat line. The loss of oil into the Geelong and Ballarat gas pipeline systems will be significantly reduced as a result of using the dry-seal compressors as lead compressors.

[15] As customers in the Geelong area have complained of liquids from the pipeline, GasNet have prioritised converting Gooding and Brooklyn (Geelong) to dry-seal operation.

4.2.4 Stage 2: BCS13 and BCS14 (2008/2009).

Like BCS10, the Saturn systems have a number of design deficiencies that bear on the safety and reliability of the plant, including 'fail-last' valves, swing-check valves, and water-cooling equipment with associated Legionella risks. Whilst some of this equipment is packaged, there is no fire suppression system[16] and the potential for oil fires remains.

Furthermore, the Stage 2 construction (BCS 6 and 7) was constructed with unit suction equipment and piping rated only to Class 300 (about 5000 kPag maximum). This equipment is therefore limited in capability and usefulness when compressing from the 7400 kPa Geelong pipeline into the Ballarat pipeline due to the compressor staging and safety limitations. By replacing the Saturns and associated equipment and piping, the proposed Centaur units will overcome this limitation and avoid upgrade costs associated with Saturn compressor restaging and replacement of sub-standard equipment.

In order to address the site safety and operability issues associated with the Saturn equipment, and to remove the wet-seal compressors which inject oil into the pipeline, the following options were investigated:

- installation of two new Centaur T4700-C336 gas compressor packages complete with balance of plant at an approximate cost of $37.6M;
- installation of four new Saturn T1600-C168 gas compressor packages complete with balance of plant at an approximate cost of $50.0M;
- installation of three new Saturn T1600-C168 gas compressor packages complete with balance of plant at an approximate cost of $38.3M; or
- installation of one new Centaur T4700-C336 and two new Saturn T1600-C168 gas compressor packages complete with balance of plant at an approximate cost of $44.4M

The selection of the larger T4700 packages would not only be more cost effective, but also would be better suited to the role of compression transfers between the SWP/BLP (500mm), the future Brooklyn Wollert pipeline (600mm) and Melbourne pipeline (750mm); whilst still having the capability of delivering gas into the Ballarat (200mm) pipeline. The matching of compressors for either Brooklyn to Ballan service or Brooklyn to Iona/Geelong service optimises the capital investment for spare capacity (ie a spare compressor is not required for each "pipeline"). This is most clearly demonstrated when considering the last two options of installing three new Saturn compressors or one new Centaur and two new Saturns. Where two Centaurs (Unit 11 and 12) run into Iona/Geelong and compression is required into the Ballarat line then the back up unit in both cases is 2 Saturns which is incapable of producing the same power as a Centaur. This means the station will be forfeiting backup.

It is proposed to install two Centaur T4700-C336 gas compressor packages into Stage 2 building. In order to achieve the works program, this stage will commence with the removal of the Saturn compressors in Stage 2 building and associated balance of plant. During construction, BCS11 and 12 will be available with BCS 8, 9 and 10 available as standby. The new packages shall be specified to be identical to BCS12 but with SoLoNox[17] option installed[18], and will also connect to

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[16] A halon fire suppression system previously at the site was removed by government regulation.

[17] SoLONox is the Solar Turbines trademark for low NOx combustion system optionally used on turbomachinery.

[18] Low NOx option for Centaur engines was not required for replacement of the Centaur BCS10 compressor package as emissions were demonstrated to be similar to the existing licence discharge point. However, replacement of Saturns with Centaur equipment represent a significant change to emission level and will require EPA Works Approval. Works are

either the Geelong or Ballarat pipeline. The works should be able to be performed without significant withdrawal of compression services from the station.

At the conclusion of the installation of these units, the remaining Saturn compressors (BCS8 and BCS9) and associated balance of plant are no longer required to operate to meet the firm service duty. However, continued availability of Centaur BCS10 and associated balance of plant is prudent to facilitate relocation of BCS11.

4.2.5 Stage 3: Relocation of Centaur BCS11 (2010/2011).

The relocation of BCS11 package to Stage 1 building is proposed to address the equipment and design deficiencies in the existing package and to facilitate the demolition of Stage 3 building.

The design deficiencies are similar to those identified for BCS10.

- Safety, including 'fail-last' unit valves, swing-check valves, and air intakes from the process gas side of the building. There is extremely poor maintenance access to elevated equipment.[19] Whilst the equipment is packaged, there is no fire containment system and the potential for oil fires remains.
- Occupational health: water-cooling equipment with associated Legionella risk.
- Environmental: the engine currently uses gas motors to start (gas emissions to air); odorised gas may cause loss of amenity to neighbours; high water usage in cooling systems; entrained oil in gas vents affects neighbouring properties.
- The existing building structure and the associated supports, plus the gas process equipment immediately adjacent to the package, interfere with maintenance access.

The demolition of the Stage 3 building and balance of plant will provide much-needed space for future development and safety separation between the compression facilities and the pipeline and regulator stations.

The remedial works may be achieved with either of the following options:

- relocation and upgrade of the existing Centaur T4000-C337 package at an approximate cost of $11.8M; or
- installation of a new Centaur T4700-C334 package at an approximate cost of $20.4M.

The significant savings achieved with relocation of the existing BCS11 unit are achievable as the BCS10 compressor will be available to provide the backup compression capability during delivery of the project.

Balance of plant includes the following:

- Fail-safe process valves utilizing instrument air;
- Outlet connections to Geelong and Ballarat pipelines;
- Anti-surge valve utilizing instrument air;
- Axial type unit non-return valves;
- Inlet filter-coalescer;

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subject to the EPA Act 1970 State Environment Policy (Air Quality Management) wherein best practice is required to reduce class 1 emission (such as NOx). Refer Clause 18 and 19.

[19] Photos 10 to 15 and 19 show congestion around unit 11 compressor package

- Fin-fan process gas cooler; and
- Fin-fan lube oil cooler.

BCS11 compressor will be re-oriented to draw inlet air from the safe side of the building. The old BCS11 balance of plant will be demolished as part of this program.

At the conclusion of Stage 3, compressor BCS 10 will be retired and the building demolished.

4.3 Stonehaven Compressor Station

4.3.1 VENCorp Report

VENCorp Timing and Planning Reports have identified that the Stonehaven compressor station provides its maximum system wide benefits if installed by 2012, with one Centaur 50 (T6100) compressor package. It is forecast that this unit will cost $26.2M.

This station will be required should flows out of the UGS/SEAGas rise above 307 TJ/day or required refill rise above 50TJ/day. This station will also provide capacity increase on the WTS by virtue of increased pressures to the Iona compressors.[20]

A site for the compressor station has been chosen and agreement reached with the landowner subject to obtaining a planning permit from the local council.

The expected scope of works will include a station control room with TMR PLC controls similar to Gooding, Brooklyn and Wollert compressor stations, utilising a local and remote Fix station HMI and connected to safe-area Solar T4000 controls similar to the Brooklyn BCS12 compressor.

4.3.2. Functionality and location

The GasNet owned Stonehaven site near Batesford is located west of Melbourne on the 500NB SWP. The station would be constructed on this greenfields site with the facility to compress either east or west, and to automatically allow gas to free-flow on the pipeline. The site would be initially designed for operation of one compressor with provision for later addition of a back-up installed compressor. Design (ie fuel gas and piping sizes) would accommodate operation of both units if required on a non-firm basis. Free-flow would be expected to be the dominant mode of operation on the pipeline with eastern compression predominantly in winter.

4.3.3 Key facilities

- Site works including clear and grade, crushed rock, perimeter fencing, vehicle and personnel access gates, internal roads/vehicle parking and site drainage.
- Buildings would include a Process Control Room (PCR) complete with batteries and Switchroom, a small workshop and storage (for essential spares, oil etc), and administration/mess room/ablutions block.
- Services required include 415 Vac and water. A local septic system is probably required.
- A backup gas-fired alternator and instrument air compressor is required.
- Oily water separator is required and interceptors to prevent escape of potential contaminated water.
- Station controls will include a station 24 Vdc and/or 110 Vdc battery system, supervisory control via an RTU, and small safety PLC to control station valves and unit controls.

[20] VENCorp Planning Report for WTS constraint

- Station pipework includes piping and valving for flow reversal: two new 500 NB linevalves, three actuated station isolation valves (fail-safe), station vent valves and vent systems. A station inlet filter/coalescer is required for protection of the compressors.
- In order to provide for equalisation of the station and restoration of free-flow (or for reversal compression) a pressure equalising regulator will be provided. (The expected pressure drops may require about 600 kW heating for this application – currently not included).
- A fuel gas conditioning skid comprising electric immersion preheating, a custody transfer meter (coriolis meter and associated flow RTU), and dual pressure reduction regulators.
- One Solar Centaur 50 (T6100=3500kW) –C334 dry-seal compressor complete with standard ventilated enclosure, fire protection, local 'TT4000' HMI and control system, inlet air filter, exhaust silencer, oil cooler, electric start motor, lube oil pump and backup lube oil pump. The engine is assumed to be a low Nox (SoLoNox) engine in accordance with EPA SEPP policy.
- Compressor 'balance of plant' (BOP) for each unit includes inlet isolation and loading valves, anti-surge valve, fin-fan gas cooler, axial style non-return valve, outlet valve and vent valve. Unit isolation and vent valves will be 'fail-safe'.

4.4 Iona Compressor Station

GasNet installed two 300 KW (400 HP) compressors at the Iona Underground Storage site in early 2000, to assist in the transmission of gas from the SWP to the Western System. The compressors are currently unable to compress from the Western system into the Principal system. Demand growth on the WTS identified in the VENCorp Planning Report has identified the need for augmentation by 2010. This requires the replacement of the existing package coolers by winter/spring 2007.

4.5 Wollert Compressor Station

Whilst maintenance support from Solar Turbines Australia is still available, the relay-based unit control systems[21], the Saturn 10 (T1200/T1300) turbine engines and the C160 compressors are all outdated technology. The C160 compressors cannot be converted to dry seals and would need to be replaced, requiring skid refurbishment in the USA. Opportunities to renovate or upgrade gas compressor packages is costly and in practice limited to uprate of engines from T1200 to T1300 (nominal 1300hp = 950kW) due to adverse and extended impact on pipeline capacity.

The following proposed strategy for re-development of the Wollert Compressor Station is set in the context of current requirements for upgrade of existing assets due to design and support deficiencies, the need to replace existing wet-seal compressors to eliminate oil injections into the pipeline,[22] and the projected augmentation program to meet short and medium term growth in demand leading to the Northern Zone, Carisbrook and Echuca constraints identified in the VENCorp Planning Reports.

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[21] See photos 25 and 26 and note 5 (section 4.2.1) for limitations of existing relay-based controls.

[22] Energy Safe Victoria letter to CEO, GasNet Australia P/L dated 27th March 2006

Fuel gas heating and filtration is required to maintain the Solar Turbines warrantee for new packages[23]. Heating is also required to avoid hydrocarbon liquid dropout[24] due to introduction of Otway gas circa 2015 with the forecast installation of the Brooklyn to Wollert pipeline. The estimated cost for the fuel gas treatment system is $1.58m.

As all compressors are located in a common compressor hall, they are also exposed to possible loss from fire due to the potential of fire from failure of oil hoses (etc). Fire can knock on to adjacent units due to the lack of fire suppression systems. Marioff Hi-Fog system will be installed as part of any replacement of compressors at the station. This cost has been included in all alternative options considered.

4.5.1 Stage 1: Automation. (2006/2007)

In its draft decision on the Access Arrangement for the Second Access Arrangement Period the ACCC approved expenditure to upgrade the Wollert compressor station, including automating the station.

The original control equipment at Wollert is no longer supportable and the Victorian Market is making much greater demands on the control capability and reliability of the station. GasNet has completed projects to automate the control systems at the LNG facility, Gooding Compressor Station and Brooklyn Compressor Station (1999). Utilisation of the Wollert compressor station has reached about 50% and is increasing to the point where dependence on compression has become significant.

The replacement of the discrete fire and gas safety control logic at Wollert was necessary due to obsolescence and lack of critical spares. A number of other control elements addressing shortcomings in the design of control and SCADA systems at the Wollert site are being implemented to upgrade the site to current Good Practice. This includes the provision of a local HMI and safety PLC utilizing established design principles which facilitate remote support and safety integrity similar to the systems installed in the LNG facility, Gooding and Brooklyn Compressor Stations. The utilities and services (415Vac, 240Vac, 24 Vdc, generator backup, safety PLC and SCADA HMI) will be utilized in the proposed re-developed station following implementation of Stage 2 and Stage 3.

The design intent during the construction period was to minimize disruption to station core operations. This required some temporary facilities to permit compression (perhaps using two compressors only) while power system motor control center (MCC), 240 Vac distribution board, station 24 Vdc power supply and station controls are installed.

Until Stage 2 is commenced, the station will continue to be exposed to failure of the existing Foxboro Spec 200 control system and potential risk of gas ingestion into units or the station building should there be a significant gas release near the compressor house. The deferral or avoidance of this work was determined through risk assessment and is justified on the basis of the short interval until completion of Stage 2 and the assessment that the associated probability of an event causing loss of equipment is very low. However, should the proposed Stage 2 works not proceed within the next Fourth Access Arrangement Period, expenditure to replace and modify existing systems will be required.

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23 Solar Turbines Specification ES9-98 Fuel, Air and Water (or Steam) for Solar Gas Turbine Engines

24 Reduction of natural gas pressure results in cooling of the gas stream (known as Joule-Thompson effect). Otway gas is known to be produced at a hydrocarbon dewpoint close to the specification limit (2 degC). If gas is allowed to cool below the hydrocarbon dewpoint the heavy components of natural gas condense as a liquid and can result in damage to gas turbine engines.

At the conclusion of Stage 1 implementation, the reliability of station controls will have improved and remote support improved. However, the compressor packages and associated balance of plant (valves etc) will continue to be exposed to moderately high failure rates due to their age and relay-based technology (which are issues to be addressed in Stage 3 development), and compressors will still inject moderate quantities of oil into the pipeline due to the wet-seal technology.

4.5.2 Stage 2: Two Centaur T4700s (2008/2009).

The VENCorp Planning Report for the Northern Zone has identified the requirement for immediate augmentation of the Wollert compressor station with equivalent of four Saturn T1200 operating compressors (ie 3400kW) plus one spare compressor. This may be achieved with either of the following options, all of which require additional station pipework and station and unit isolation valves:

- the installation of two Centaur 40 T4700 compressor packages at an approximate cost of \$39.6M;
- the installation of four new Saturn 20 T1600 compressor packages (to achieve 3400kW with three compressors operating) at an approximate cost of \$48M; or
- the upgrade of three existing Saturn 10 T1200 compressor packages with C168 dry-seal compressors, plus two new Saturn 20 T1600 compressor packages at an approximate cost of \$51M.

Even in the absence of the requirement by the ESV to replace the existing Saturns with dry seal machines, the most efficient approach in present value terms is to remove the existing Saturns and replace them with Centaurs in 2009 (\$39.6m), rather than install two Saturns in 2009 to provide the required additional capacity as identified by VENCorp and then in 2011 replace the existing Saturns (\$47.5m).

The selection of the larger T4700 packages would not only be more cost effective, but also would be better suited to the role of compression transfers between the SWP (600mm) and Pakenham-Wollert pipeline (750mm), whilst still having the capability of delivering gas into the Wollert-Wodonga (300mm) pipeline as identified in the VENCorp Vision 2030 document by 2015 for ‘east-west’ compression of Longford gas. The identified requirement for 6 MW compression power would be achieved with the addition of one additional T4700 compressor package by 2015 (Stage 3).

This is also expected to be less disruptive to station operations than the alternative of separate projects to up-rate engines from T1200 to T1600, unit controls retrofit from relay logic to PLC controls, replacement of compressors to provide for dry seals and possible re-staging, and associated upgrade to balance of plant (fail-safe valves, surge control valves etc).

The project would provide for future connection points to the station pipework for the SWP/BLP extension, on the basis that the station will initially have a single point of suction and single point of delivery to the Wodonga pipeline during operation. Each unit will incorporate an inlet filter/separator and gas cooler which will facilitate later augmentation to achieve the east-west gas transfers foreshadowed in the VENCorp Vision 2030 report.

The proposed works will involve expansion of the station automation system and will use packaged Solar Centaur dry seal compressor sets similar the latest Brooklyn C336 compressor

BCS12 and fitted with SoLoNox combustion in accordance with EPA SEPP.[25] Solar packaging similar to the electric start Springhurst station and incorporating integrated unit fire and gas detection and fire suppression will be employed, resulting in minimal station controls impact. The compressor station works will include new station air and fuel gas utilities and a station re-cycle valve for load control. The project will also establish new station fail-safe isolation valves and station gas headers, connecting to new unit isolation and control valves (again using fail-safe principles) and a new station vent. An instrument air system will be required for these new facilities. The opportunity will be taken to remove the three non-return valves which directly connect Class 600 pipelines to the Class 300 Keon Park (Melbourne) system.[26]

At the conclusion of Stage 2, the two electric-start dry seal compressors (T4700 engines) would be the primary compressors used for service, whilst the existing wet-seal compressors (T1200 engines) and associated station pipework and balance of plant would be retired and demolished.

4.5.3 Stage 2: Station Piping issues

The VENCorp Planning report has also identified the need for duplication of the Wollert to Wandong section of the Wollert to Wodonga pipeline in order to address the constraints at Echuca and Culcairn. This is of relevance to the pipeline route selection for the Wollert to Rockbank pipeline as this pipeline may also need to parallel the existing pipeline north due to the 'green wedge' north-east of Wollert. The opportunity may therefore exist to bring forward the construction of a section of the Wollert to Rockbank pipeline in order to avoid costly duplication of pipelines in this easement.

It is therefore recommended that further work be done on preliminary pipeline route selection and system planning to establish the feasibility and benefits of a single additional pipeline rated to 10.2 MPaG.

4.5.4 Stage 3: One Centaur 40 T4700 (2015)

The introduction of Otway gas is projected to be possible from about 2015 with the installation of the Wollert to Rockbank/Brooklyn pipeline (WBP). The requirements for 6 MW power as identified in the VENCorp Vision 2030 may be met with one additional Centaur 40 T4700 package. However, scope of station works may include connections from and/or to the new 10.2 MPa WBP pipeline. For example, there may be a requirement for Wollert compressors to inject Otway gas into the Wollert to Wodonga pipeline, or to inject Longford gas into either the SWP or the Wodonga pipeline. Further, definition of the functional requirements and identification of possible re-staging will be required prior to the following reset (2013-2017).

Construction of Stage 3 should be possible with minimal impact on station availability due to segregation of Stage 2 compressor facilities, even if the existing compressor house is re-used for the Stage 3 compressor.

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[25] Environment Protection Act 1970 (Vic) - State Environment Protection Policy (Air Quality Management) clauses 18 and 19 requires best practice in reducing class 1 emissions.

[26] The latest revision to AS2885.1 Clause 7.2.2 states '…a different MAOP, the minimum requirement for separation by isolation is two isolation components, two valves or one valve and a blind.' The single non-return valve does not meet this minimum requirement and represents a risk of overpressure of the lower pressure systems should the non-return valve fail to correctly close.

4.6 *Euroa Compressor Station (2009)*

4.6.1 VENCorp Report

The VENCorp Northern Planning Report has identified the installation of a Solar Saturn compressor upstream from the branch to Echuca at Euroa as part of the most cost effective solution to the Northern Zone Constraint.

GasNet currently owns land at this site but there are known landowner objections to GasNet building on this site. A possible location has been suggested downstream from this site at Violet Town but this is less suitable to solve the Euroa constraint.

The options investigated include the following:

- Installation of two Saturn T1600-C168 compressor packages on a new site at Euroa at an approximate cost of $24.9M; or
- Installation of one Saturn T1600-C168 compressor package on a new site at Euroa, and a new Saturn T1600-C168 compressor package and pipework modifications at Springhurst at an approximate cost of $27.8M.

The preferred option is construction at the Euroa site. Due to the target commissioning dates and possible delays with landowner negotiation it is recommended that work commence immediately with acquiring suitable land and buffer areas.

4.6.2 Functionality and location

The GasNet owned site near Euroa is located northeast of Melbourne on the 300NB Wollert to Wodonga pipeline. The station would be constructed on this greenfields site with the facility to compress either north or south, and to automatically allow gas to free-flow on the pipeline. The site would be designed for operation of one compressor with a back-up installed compressor. Both units may be operated if required on a non-firm basis. Free-flow would be expected to be the dominant mode of operation on the pipeline with northern compression predominantly in winter.

4.6.3 Key facilities

- Site works including clear and grade, crushed rock, perimeter fencing, vehicle and personnel access gates, internal roads/vehicle parking and site drainage.
- Buildings would include a Process Control Room (PCR) complete with batteries and Switchroom, a small workshop and storage (for essential spares, oil etc), and administration/mess room/ablutions block.
- Services required include 415 Vac and water. A local septic system is probably required.
- A backup gas-fired alternator and instrument air compressor is required.
- Oily water separator is required and interceptors to prevent escape of potential contaminated water.
- Station controls will include a station 24 Vdc battery system, supervisory control via an RTU, and small safety PLC to control station valves and unit controls.
- Station pipework includes piping and valving for flow reversal: a new 300 NB linevalve, three actuated station isolation valves (fail-safe), station vent valves and vent systems. A station inlet filter/coalescer is required for protection of the compressors.

- In order to provide for equalisation of the station and restoration of free-flow (or for reversal compression) a small pressure equalising regulator is included. (The expected pressure drops should not require heating for this application).
- A piping connection from the northern (Wodonga) side of the 300NB pipeline to the Echuca lateral is required (to ensure the Echuca system is not constrained).
- A fuel gas conditioning skid comprising electric immersion preheating, a custody transfer meter (coriolis meter and associated flow RTU), and dual pressure reduction regulators.
- Two Solar Saturn 20 (T1600=1185kW) C168 dry-seal compressors each complete with standard ventilated enclosure, fire protection, local 'TT4000' HMI and control system, inlet air filters, exhaust silencers, oil coolers, electric start motors, lube oil pump and backup lube oil pump.
- Compressor 'balance of plant' for each unit includes inlet isolation and loading valves, anti-surge valve, fin-fan gas cooler, axial style non-return valve, outlet valve and vent valve. Unit isolation and vent valves will be 'fail-safe'.

4.7 Springhurst Compressor Station

The VENCorp Planning report has identified a possible solution to be the augmentation of the Springhurst compressor station, possibly by installing a Saturn compressor, to relieve the Northern Zone constraint.

The Springhurst compressor station augmentation project would comprise the addition of a Saturn T1600 compressor with safe area TT4000 controls and station automation (refer section 5). Station valves and controls to enable compression in either direction, plus pressure reduction facilities to equalize pressures to support mode change, would also be required.

The GasNet proposed option is to install compression at Euroa and not perform works at Springhurst during the current Regulatory Reset 2008 to 2012.

4.8 Rockbank Compressor Station

Although no current modelling scenarios conducted by VENCorp or GasNet have identified the need for future compression at Rockbank, current long-term modelling beyond 2015 presumes that compression will be possible at Brooklyn to re-compress gas carried from Wollert into the SWP to Iona. However, the very restricted site area at Brooklyn and the difficulty in access to the easement between Rockbank and Brooklyn suggests the four proposed pipelines into the Brooklyn compressor station are unlikely to be feasible. (Note, VENCorp Vision 2030 and GasNet modelling identify SWP to comprise three parallel 500mm pipelines by 2030).

It is recommended that further modelling be conducted into the feasibility of alternatives to utilising Brooklyn for SWP re-compression, including preliminary siting studies for a potential compressor site at or near Hopkins Rd, Rockbank. This site is a key junction of the Sunbury, Sunbury loop, Ballan, Brooklyn-Lara and (future) Wollert pipelines and may therefore be the preferred site for pressure regulation stations.

5.0 Station Automation

Whilst compressor stations have a potential design life of about 25 to 30 years, control equipment at compressor stations has a relatively limited life (about 15 years) due to the greater demands on the control capability and reliability of the stations and lack of support from suppliers. The first cycle of automation upgrades commenced with Gooding (1998) and Brooklyn (1999).

5.1 Gooding Compressor Station

Gooding utilises Tricon TMR station PLC which provides critical safety and control functions.

The existing Fix station HMI is connected to the GasNet corporate SCADA LAN and is expected to be supportable through to 2012. The Dandenong control room Fix workstation accesses the station HMI via the SCADA LAN.

Gooding compressors are currently fitted with hazardous area unit HMI (TT2) and PLC5 controls which will still be supportable through to 2012. However, there is no remote IP access to this generation of unit HMI and it is proposed to provide a composite windows-based Solar Turbotronics TT4000 HMI after 2012 which will also facilitate unit fault diagnostics and commissioning of the new dry-seal compressors.

5.2 Brooklyn Compressor Station

Brooklyn also utilises Tricon TMR station PLCs which provide critical safety and control functions. These PLCs are configured as a station ESD PLC and a station Integrated Unit Control System (IUCS). The station Tricon systems will be expanded as part of the BCS12 and Brooklyn Lara Pipeline projects over 2007 and 2008. These systems will include the site pressure regulating stations (Brooklyn City Gate, BLP City Gate and Brooklyn Pressure Limiter) to provide integrated control of the site.

The existing Fix station HMI is expected to be supportable through to 2012. The Dandenong control room Fix workstation accesses the station HMI via the SCADA LAN.

The Centaur BCS10 and BCS11 compressors are currently each fitted with hazardous area unit Allen Bradley PLC5 controls which will still be supportable over the next few years. However, support for the DOS-based HMI (TT2) is limited and there is no remote IP access to this generation of remote HMI. A composite windows-based Solar Turbotronics TT4000 HMI will be provided as part of the current BCS12 project to install the new dry-seal T4700-C336 compressor. The Saturn compressors BCS 6,7,8 and 9 utilise relay-based logic and as such diagnostic support is very limited for this generation of controls. It is proposed to replace the Saturn compressors with better suited compressor packages with current generation TT4000 unit controls in preference to providing unit controls retrofit (refer to section 4.2).

5.3 Iona Compressor Station

Station controls are currently provided through the supervisory Bristol RTU for the compressor station as there are no instrumented safety critical functions on site. (ie there is no requirement to isolate and vent the small-bore station pipework). There is no SCADA LAN currently established on site and all data depends on SCADA transmissions on the Telstra DDN line. Telstra advise DDN services are expected to be withdrawn by 2010 and GasNet is currently investigating options. Upgrade of the controls to an IP based Bristol ControlWave RTU or safety PLC is likely to be required prior to 2012 along with establishment of an alternate communications system.

Provision of a local station Fix HMI is currently being installed for the Iona compressor station in 2007 which will also provide local display of the adjacent Iona City Gate and Iona Fuel Gas Meter (CTM) facilities. The Dandenong control room Fix workstation already provides a remote operator interface via the GasNet Open Enterprise SCADA system.

Each compressor has a small Allen Bradley local display console that is expected to be supportable through to 2012. Remote support for this equipment is currently not established. This significantly affects the ability of GasNet to respond to equipment problems.

5.4 Wollert Compressor Station

Automation of Wollert is currently in the design phase for installation in 2007. The station safety (ESD) and control system will comprise a Tricon TMR PLC to control the compressor station together with a Trident TMR PLC to control the regulator stations (Wollert City Gate and Wollert Pressure Limiter) and station isolation valves.

Provision of a local station Fix HMI is also being installed for the Wollert compressor station in 2007 which will also provide local display of the adjacent Wollert City Gate and Wollert Pressure Limiter facilities. The Dandenong control room Fix workstation will be configured to provide a remote operator interface via a new corporate and SCADA LAN communications system.

The Saturn compressors WCS 1, 2, and 3 utilise obsolete relay-based logic and, as with the Brooklyn Saturns, diagnostic support is very limited for this generation of controls. It is proposed to replace the Saturn compressors with better suited compressor packages with current generation TT4000 unit controls in preference to providing unit controls retrofit (refer to section 4.5).

5.4 Springhurst Compressor Station

Like the Iona station, station controls are currently provided through the supervisory Bristol RTU for the compressor station. This was implemented as a simplified station control system due to the fast-track nature of the winter 99 (post Esso Longford explosion) projects, and safety-critical functions have been implemented using discrete switch-and-relay logic. There is no SCADA LAN currently established on site and all data depends on SCADA transmissions on the Telstra DDN line. Telstra advise DDN services are expected to be withdrawn by 2010. Upgrade of the controls to an IP based Bristol ControlWave RTU or safety PLC is required prior to 2012 along with establishment of an alternate communications system. Should a second compressor be required at this site to achieve Culcairn exports commitments (refer to the VENCorp Northern Zone Planning Report), then a safety PLC will be required. This is not anticipated to be required under the proposed scope of works for the Third Access Arrangement Period.

The existing local Fix station HMI is expected to be supportable through to 2012. The Dandenong control room Fix workstation accesses the station HMI via the DDN service.

The compressor has a safe-area Allen Bradley Flex I/O control PLC that is expected to be supportable through to 2012. The local TT2 display console is no longer supported and has been replaced with alternative ‘Windows’ HMI due to failure. Remote support for this equipment is currently not established and not proposed for the Third Access Arrangement Period.

6.0 Upgrade and Overhaul of Compressor Engines

The engine overhaul program has been based on scheduled turbine life programs under the Solar Turbines Alliance Agreement, with some early life overhauls conducted in response to annual condition reports or faults. The high start count at Gooding is considered to be a contributing factor to the short life of this equipment.

Overhauls of the installed engine base is summarized below:

Date	Tag	Engine Hours at time of overhaul/repair	Comments
	WCS1		Original engine.
	WCS2		T1202 from BCS6, overhauled & uprated Dec 2003
	WCS3		Original engine.
	BCS4	35,123	Uprated and removed from service; relocated to BCS9
	BCS5	36,062	Uprated and removed from service; relocated to BCS7
	BCS6	38,515	Removed from service & relocated to WCS2, then uprated
	BCS7	48,232	Removed from service; relocate to storage
	BCS8		Original engine.
	BCS9	16,532	Repaired 2007 following PT failure
	BCS10	31,049	Overhauled Dec 2007
	BCS11	29,277	Overhauled Nov 2000
	GCS1	15,218	Overhauled Apr 1992
	GCS2	10,339	Overhauled Apr 1997
	GCS3	20,910	Due for overhaul, possible uprate to T4502
	GCS4	11,976	Overhauled Mar 1998

Appendix 1 Summary of Major Works by Station

Station	Compressors	Status
Eastern – Longford to Melbourne		
Gooding	GCS1 - Solar Centaur T4002,	Compressor restaged Feb 1983 Overhaul engine Apr 1992 PT overhaul 1994 Control system upgraded to TT2 1998. C402 dry seal compressor install 2007/8
	GCS2 - Solar Centaur T4002	Compressor restaged Feb 1983 Overhaul engine 10326hrs Apr 1997 Control system upgraded to TT2 1998 C402 dry seal compressor install 2007/8
	GCS3 - Solar Centaur T4002	Compressor restaged Feb 1983 Control system upgraded to TT2 1998 C402 dry seal compressor install 2007/8
	GCS4 - Solar Centaur T4002	Compressor restaged Feb 1983 Overhaul engine 11976hrs Mar 1998 Control system upgraded to TT2 1998 C402 dry seal Compressor installed 2007
South-Western – Melbourne to Portland		
Brooklyn	BCS6 - Solar Saturn T1202	Engine replaced with WCS2 engine 2000
	BCS7 - Solar Saturn T1302	Engine replaced with BCS5 engine 1999
	BCS8 - Solar Saturn T1202	Compressor damaged due to failed NRV Feb 1992
	BCS9 - Solar Saturn T1302	Engine replaced with BCS4 engine 2007
	BCS10 - Solar Centaur T4002	Compressor re-staged Aug 1993 Compressor re-staged Oct 1999 Control system upgraded Dec 1999 PT overhaul at 28000hrs 2004 Engine reverse spin (NRV fail) 2006 Engine overhaul at 31049hrs Dec 2007
	BCS11 - Solar Centaur T4002	Compressor restaged Feb 1985 Control system upgraded Dec 1999 Engine overhaul at 29277hrs Nov 2000 C337 dry seal compressor installed 2006
	BCS12 – Solar Centaur T4702	C336 dry seal compressor installed 2007
	BCS4 Solar Saturn T1302	Engine up-rated to T1302 Jan 1998 Skid removed Jun 1998 (Euroa) Engine installed in BCS9 Mar 2007
	BCS5 Solar Saturn T1302	Engine up-rated to T1302 Jan 1998 Skid removed Jun 1998 (Young) Engine installed in BCS7 Jan 1999
Stonehaven		Tie-in pipework on site. Land allocated.

		First Centaur T6100 to be installed by 2012.
Iona	ICS1 - Caterpillar engine with Gemini Recip compressor ICS2 - Caterpillar engine with Gemini Recip compressor	Station is capable of compression west only. Unit coolers undersized – to be replaced by 2007.
Northern – Melbourne to Culcairn/Young		
Wollert	WCS1 - Solar Saturn T1202 WCS2 - Solar Saturn T1302 WCS2 - Solar Saturn T1202	Compressor re-staged Aug 1997 Compressor re-staged Aug 1997 Engine FOD – repl. with BCS7 engine 2000 Engine up-rated to T1302 Dec 2003. Compressor re-staged Aug 1997 Engine & compressor damaged by reverse spin Apr 2002 (NRV failure) Station cooler and recycle valve inst'd 2004 Safety controls to be installed by Dec-2007
Euroa		New facility to be constructed at or near existing site at junction of Wodonga and Euroa pipelines.
Springhurst	SCS1- Solar Centaur T6102	Capable of compressing south only, requires pipework modifications to be able to compress north. Oversized for 300mm pipeline. No standby unit. TT2 HMI replaced 2006

Appendix 2 Site Photos

Photo 1: Brooklyn cooling towers

The Stage 2 cooling towers in the foreground and Stage 3 cooling towers in the background. Water corrosion and bacteriological treatment facilities are housed in the control cubicle between the systems. Note potential for overspill.

Photo 2: Brooklyn cooling towers

Note the proximity of water systems to gas process equipment. The potential for Legionella bacteria must be diligently managed. The cooling towers in the background service stage 3 Saturns and Centaurs.

Photo 3: Brooklyn inlet separators and watercooled gas exchangers for Saturns 6, 7, 8 and 9

Process tube failure in coolers has lead to water ingress into compressor, engine and oil tank resulting in oil spill and damage to gas turbine equipment.

Photo 4: Saturn unit isolation valves, inlet scrubber and watercooled exchanger

The stage 2 suction equipment (inlet valves, piping and inlet scrubber) are rated Class 300 (max 5000 kPa) but are connected to Geelong pipeline (MAOP 7400 kPa).

Photo 5: Brooklyn station vent adjacent to bicycle track

Gas is released regularly from the vent stack as part of normal operations. Gas odour and entrained oil has become a problem to neighbours. This small site is accessible to the site boundary by the public on all sides.

Photo 6: Brooklyn, stage one building, control room in foreground

The stage 1 buiding will house the new Centaur T4700 package currently being installed by end 2007.

Photo 7: Rear of stage one building, with air receivers in foreground

The Saturn air intakes are located on the “safe” side of the building and can be seen at the left.

Photo 8: Brooklyn stage 2 building with congested pipework in foreground

Access is difficult and presents a safety hazard for maintenance personnel. The two units at left are BCS 4 and 5 which were removed from service following the Longford incident in 1998.

Photo 9: Brooklyn, stage two building with congested pipework and cooling towers in foreground

Stage three building in the background.

Photo 10: Brooklyn Centaur 11 and watercooled exchanger in foreground, showing congestion of process equipment which interferes with maintenance

Note proximity of air inlet which is adjacent to high pressure gas process equipment.

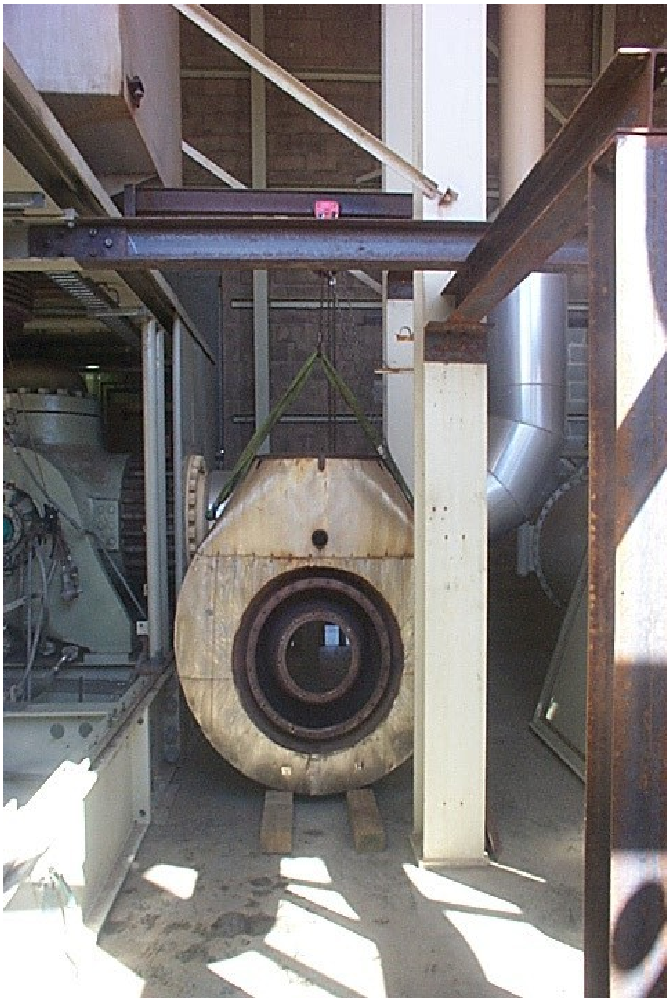
Photo 11: Brooklyn Centaur package in stage three building showing interference with building support piers and congestion with processing equipment adjacent to hot services.

Engine removal for maintenance is very difficult due to the lack of adequate layout areas adjacent to the package and inability to manoevour cranes in the vicinity.

Photo 12:Centaur BCS10 engine removal from Brooklyn in stage three

Note the difficulty in locating appropriate lifting points with slings on adjacent BCS 11 process pipework.

Photo 13: Brooklyn Centaur engine showing difficult removal during engine maintenance



Note adjacent building support piers and operating processing equipment adjacent. Equipment must be manoevered around pressurised process pipework.

Photo 14: Brooklyn stage 3 standard Solar enclosure

Photo 15: Solar Centaur enclosure

Photo 16: Brooklyn high-pressure water bath heater adjacent to stage three building

Photo 17: Brooklyn high-pressure water bath heater

Flue stacks can be seen in the foreground and process gas connections in the background.

Photo 18: Brooklyn Centaur inlet air filter

Note proximity to high-pressure gas process equipment. Ingestion of gas into a running engine can lead to uncontrolled “runaway” of the engine which would lead to overspeed and catastrophic failure of the engine. Typically, engine air compressor blades can fail and erupt through the engine casing.

Photo 19: Brooklyn stage three building showing high-pressure watercooled exchanger adjacent to Centaur unit 11

Photo 20: Brooklyn Saturn unit isolation valves

These valves are double-acting "fail-last" action which can result in failure to isolate gas in event of hazardous situations, which can then lead to escalation of events and potential total loss of the station. The relay-based Saturn logic restricts the opportunity to improve station safety.

Photo 21: Brooklyn station pipework adjacent to stage two building

Photo 22: Brooklyn Centaur Unit 11 anti-search valves, adjacent to air inlet

Note this equipment is operated using natural gas. Significant releases such as gasket joint failure could lead to ingestion of gas into the engine and subsequent engine failure.

Photo 23: Wollert station inlet suction scrubber

Note the close proximity to control room entrance door at left which is the main access.

Photo 24: Wollert station and unit piping

Note air inlets, three units and the control building adjacent to high-pressure piping and equipment. Significant gas leaks from process equipment and venting valves may be ingested into operating engines and the building leading to potential engine failure and explosion respectively. The station vent can be seen in the background and is marginally too close to air intakes under unfavourable wind conditions.

Photo 25: Wollert Saturn T1200 compressors in compressor building

Note relay technology, circa 1970 and lack of fire protection. Fault-finding on relay based logic requires on-site attendance and is made particularly difficult if adjacent units are operating due to the extremely noisy environment.

Photo 26: Wollert Saturn compressors

Whilst access to equipment is acceptable, the location in a common hall exposes the whole station to loss from oil fire in one unit. Failure of the high pressure oil hoses is one of the most common causes of failure and fire in this equipment.

GasNet Access Arrangement Submission (Schedules & Attachments)

Attachment D - GasNet Scope and Workload Changes Report

Operating and Maintenance Expenditure Scope and Work Load Changes

2008 to 2012

April 2007

Contents

1.0 Introduction

GasNet has conducted a review of its internal and external cost drivers for the Third Access Arrangement Period in order to identify areas where costs are likely to change from the base year of 2006 as a result of changes in the scope of activities undertaken.

GasNet's proposed workload changes include a step change for the increase in operations and maintenance expenditure as a result of capital expenditure in the regulated network.

GasNet's proposed scope changes include:

- the escalation of labour costs above inflation, including increases in labour costs arising from an ageing workforce;
- the costs of updating GasNet's existing procedures as the result of recent changes in legislation;
- the costs of increased security at GasNet's facilities;
- the increased costs of monitoring GasNet's infrastructure and facilities due to urban encroachment;
- pipeline risk assessment costs not incurred in 2006; and
- the increasing need for hazardous area reviews of GasNet's assets.

Each of these identified scope and workload changes are discussed in detail below.

2.0 Operating and maintenance costs of new assets

GasNet plans significant upgrades to and augmentation of the PTS over the Third Access Arrangement Period. This will involve the construction of a number of new pipelines and a number of additional compressor stations, regulators and heater facilities. Therefore it is reasonable to anticipate an increase in the associated operating and maintenance costs for these facilities.

In order to estimate the incremental operating costs, GasNet has identified the principal cost driver associated with each asset. By forecasting the main cost driver, it is possible to estimate the associated operating costs (based on the current annual direct costs of these type of assets).

GasNet's main areas of activity are pipeline operations, compressor operations, and regulator /heater operations. The associated cost drivers for the new assets are as follows:

Activity	Cost driver
Pipeline costs	Total length of the pipeline system
Compressor costs	Total replacement cost of the compressor stations
Regulator/heater costs	Total replacement cost of the regulator stations / heater

The underlying principle is that the length of a pipeline determines its operating costs, and not the diameter or capacity. Similarly, the cost of operating and maintaining a compressor/regulator/heater station will depend on the complexity of the asset, which is reasonably represented by its capital cost.

Based on the capital expenditure plans set out in the Submissions for the draft Access Arrangement, a forecast of each cost driver has been prepared. This has been converted into a forecast of operating costs for the Third Access Arrangement Period by applying the unit rates applicable in 2006.

3.0 Increase in real labour costs

GasNet has applied a real escalator of 2.8% to the labour component of the Non Capital Costs, on the basis that:

- real wages growth in the electricity, gas and water sector is forecast to average 2.8 per cent per annum over the next six years from 2007/2008 to 2012/2013 according to the BIS Shrapnel report prepared for Envestra, SP - Ausnet and Multinet Gas, March 2007 (BIS Shrapnel Report);[1]
- the Commonwealth Treasury Budget 2006-07 noted that wages are expected to increase solidly, with the Wage Price Index forecast to grow by 4 per cent in 2006-07[2];
- the electricity, gas and water industry sector has experienced skilled labour shortages over the past 2 to 3 years[3], and job vacancies in the electricity, gas and water sector remain relatively high;
- skilled labour shortages are expected to be exacerbated by a number of electricity and gas utilities across Australia embarking on significantly increased maintenance and refurbishment programs; and
- strong wage pressures have seen wage increases in the electricity, gas and water sector (as measured by the Wage Cost Index[4] and the labour price index[5]) well above the national average over the past six years. The ABS wage cost index and the BIS Shrapnel labour price index for the electricity, gas and water sector have averaged around 0.6 per cent and 0.7% higher than the national average from 1998 to 2006[6]. Given the current levels of skill shortages being reported and the factors listed above, the differential between wages growth in the electricity, gas and water sector and the national average is expected to be maintained over the medium-term.

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[1] BIS Shrapnel, *Outlook for Wages to 2012/13: Electricity, Gas and Water Sector Australia and Victoria*, prepared for Envestra, SP - Ausnet and Multinet Gas, March 2007, page 3.

[2] Commonwealth Treasury Budget 2006-07, Budget Paper Number 3.

[3] See Access Economics Pty Limited, *Wage growth forecasts in the utilities sector - Report to the Australian Energy Regulator*, 17 November 2006; BIS Shrapnel Report, page 24 and 29.

[4] The wage cost (price) index (ABS cat. no. 6345.0) is the ABS preferred measure of movements in wages and salaries. This is because the wage cost index provides a direct measures of change in wage and salary rates on a "constant quality" basis.

[5] The labour price index is "a CPI-style measure of changes in wage and salary costs based on a weighted combination of a surveyed 'basket' of jobs". It excludes "the compositional effects of shifts within the labour market, such as shifts between sectors and within firms": BIS Shrapnel Report, page 9.

[6] Further, growth in average weekly ordinary time earnings in the sector has averaged almost 2 per cent higher than the national average over the past 10 years.

4.0 IT costs

4.1 Disaster Recovery Site ($50k p.a.)

GasNet estimates that it will incur ongoing costs of $50,000 per annum for the ongoing operation of an IT disaster recovery centre which will be set up in Brooklyn.

The disaster recovery centre will be located away from GasNet Australia's main administrative building. This is to ensure that in the event of a failure at GasNet's Head Office, GasNet will be able to continue with core activities that ensure the safety and integrity of GasNet's pipelines and facilities, and that GasNet's systems will be recoverable without delay.

The disaster recovery centre will provide IT redundancy and data replication. The GasNet finance, e-mail, SCADA and critical file storage systems will be duplicated and stored at the Brooklyn Centre.

The additional costs relate to additional costs for telecommunications services to support the key communication systems being duplicated, maintaining this facility in an air conditioned environment and updating the systems so that they remain compatible with both VENCorp's and the main GasNet IT systems.

4.2 Compressor Station Communications Upgrades (30k p.a.)

GasNet proposes to upgrade the communications to GasNet's compressor sites from the current Low Speed DDN (Serial) system to a Frame Relay (IP) based network in 2007. This is estimated to cost an additional $30,000 per annum.

5.0 Update and Review of Operating Procedures

A review of all of GasNet's existing operating procedures is required to ensure that they are all compliant with recent changes to health and safety legislation, the *Pipelines Act 1967* (Vic) and recent and proposed changes to Australian Standard (AS) 2885.

GasNet's policies and procedures are maintained within GasNet's intranet system which is available to operational personnel. In many cases, procedures are specific to the assets or facilities to which they relate, and the procedures allow field personnel to conduct works on those assets or facilities safely and efficiently. Policies and procedures also allow GasNet to ensure that its field workers undertake maintenance work on assets in the same way – conversely, without procedures, field workers will maintain an asset based on their past experience or on generic procedures which may not take particular safety measures into account.

In order to meet its obligations under the Safety Case and AS 2885.3 GasNet must ensure that all its policies and procedures are reviewed periodically, so that changes in tools, technology, safety requirements and legislation, enterprise bargaining agreements and the environment around the asset are taken into account within the policies and procedures.

This means that GasNet will need to review all of its policies and procedures at least once during the Third Access Arrangement Period to ensure they continue to comply with all of the applicable legislation, regulations and standards, and remain appropriate for the particular asset or facility.

Further, while GasNet currently has generic procedures in place for all types of assets and facilities, and specific procedures for safety critical assets and facilities, there is a backlog of outstanding policies and procedures relating to specific procedures for non-critical assets and facilities in both GasNet's pipeline group and its facilities management group.

As a result, GasNet requires a further 400 policies and procedures in relation to the PTS.

Only 20 policies or procedures were prepared in 2006 and therefore the majority of this expenditure is a 'scope change' for the purposes of establishing GasNet's Non Capital Costs for the Third Access Arrangement Period.

The components to GasNet's proposed scope change expenditure are as follows:

- work to draft 400 new policies or procedures to ensure that GasNet is up to date; and

- work to review approximately 1000 policies and procedures every three years, or around 330 procedures per annum.

GasNet believes that the most efficient way to meet this obligation is not to use contractors, but to employ one additional technical manager within the pipelines group with responsibility for this work across both the pipelines and facilities management area.

GasNet therefore forecasts the expenditure requirement for this scope change at $60,000 per annum including non salary labour costs (other than office accommodation and other fixed costs already included in the 2006 base year).

6.0 Security Upgrades of Key Facilities and Pipelines

In 2003, the Victorian Government brought into effect the *Terrorism (Community Protection) Act 2003* (Vic). Part 6 of this Act refers to essential services infrastructure risk management, and provides for the involvement of the operators of essential services in planning for the protection of these essential services from the effects of terrorist acts.

Section 28 of the Act provides that the Governor in Council on the recommendation of the relevant Minister for the essential service, by Order, may declare that Part 6 will apply to an essential service or to any part of an essential service.

The PTS was, shortly after the enactment of the Act, declared as an essential service by the Governor in Council. This means that:

- under section 29 of the Act, GasNet must prepare a risk management plan;

- under section 32 of the Act, GasNet must audit and update the risk management plan on an annual basis to ensure that the plan is still adequate, and ensure that the plan is updated as practicable after an audit of the plan to address any deficiencies identified in the audit; and

- under section 33 of the Act, GasNet must prepare a training exercise to test the operation of the risk management plan and participate in that training exercise under the supervision of the Chief Commissioner and the relevant Minister.

GasNet commissioned an external audit of its risk management plan in 2006, in line with section 32 of the Act. The audit recommended that GasNet undertake a range of capital (see section 7.6.6 of the Submission) and non-capital expenditure in order to meet GasNet's risk management plan, which was developed in accordance with the requirements of the Act. The non-capital expenditure would provide for additional security patrols, remote monitoring, and security assessment and capability programs.

GasNet forecasts that it will require an increasing amount of operational maintenance expenditure in the Third Access Arrangement Period, rising to around $180,000 per annum by 2009, escalating at CPI.

The $180,000 comprises the following costs:

- Maintenance - $85,000

  This is for 3 visits to check security equipment per annum. This is in line with the proposed capital expenditure of $2.93 million for security upgrades over the first three years of the new access arrangement period (see section 7.6.5 of the Submission).

- Site Lighting - $20,000

  This is for the ongoing costs associated with upgraded lighting at approximately 9 sites (see section 7.6.5 of the Submission).

- Emergency Exercise - $20,000

  This is to bring in an external consultant to run the emergency exercise. This is required because GasNet does not have the expertise to conduct an exercise of this nature.

- Additional security support - $55,000

  This is the costs of additional security support from a security firm, including responding to alarms on-site. This estimate is based on the security support currently provided to GasNet.

7.0 Risk Assessments of Pipelines

Like other gas transmission pipeline companies, GasNet undertakes two types of asset risk assessments:

- design risk assessments – these are risk assessments undertaken by GasNet as part of the design and procurement process for new capital expenditure. The costs of these activities are capitalised and included in capital expenditure forecasts and are therefore not included in this scope change assessment; and

- integrity assessments of existing pipeline infrastructure – these are required under AS 2885 (see below).

The integrity assessments are undertaken by GasNet every five years. The cost of these activities is included in Non Capital Costs. This is a scope change because GasNet did not undertake any assessments in 2006 as no assessments were due.

AS 2885.1 requires that GasNet identifies and assesses risks associated with threats to a pipeline and instigates appropriate measures to mitigate these threats. In addition, section 3.4.1 of AS 2885.3 requires that a number of minimum areas must be identified in this risk assessment and must be included in a Safety and Operating Plan. The Safety and Operating Plan must, under section 3.4.1(c) of AS 2885.3, include *operating authority review measures* such as:

- regular review of Maximum Allowable Operating Pressure (MAOP) in accordance with Section 8.6 of AS 2885.3; and

- review of class location in accordance with Section 8.7 of AS 2885.3.

Section 8.6 sets out the requirements on GasNet to conduct a regular review of MAOP and requires that:

> *"The MAOP of each pipeline shall be reviewed at approved intervals not exceeding 5 years and, if necessary, amended whenever there are changes (including corrosion or damage) that could adversely affect the safety of the public, the operating personnel or the integrity of the pipeline. Investigations, tests and calculations shall be made during the review to establish the current condition of the pipeline and to determine an MAOP in accordance with AS 2885.1, this Section and Appendix D."*

Appendix D of AS 2885.3 sets out approved methods that may be used when the suitability for service of a pipeline having corrosion damage is being assessed.

Section 8.7 requires GasNet to review pipeline classifications. In particular, this section requires that:

> *"At approved intervals not exceeding 5 years and at any time when patrolling indicates the possibility of a need to change the classification of a location, the classification of the locations along the route of the pipeline shall be reviewed and, if necessary, changed. Appropriate corrective action shall be taken, including a risk assessment carried out in accordance with the requirements of AS 2885.1."*

Section 8.8 further requires that:

> *"….. at a period not exceeding 5 years (or as approved) an identification shall be made of the threats that could result in hazardous events affecting the pipeline. Threat mitigation procedures, failure analysis and risk evaluation shall be reviewed at those times."*

In practice, assessments under sections 8.6, 8.7 and 8.8 of AS 2885.3 are undertaken at the same time, and is a labour intensive process which requires GasNet to conduct:

- assessments under Appendix D of AS 2885.3 using assessments by either pressure testing, or calculation of MAOP. This involves:
    - for pressure testing, re-testing a corroded section of a pipeline hydrostatically to a pressure that would not cause the pipe to leak or lose its integrity. This is carried out only after the appropriate safety measures had been taken and an estimate of the appropriate test pressure made; and
    - for the calculation method, calculating the pressure at which the pipe is expected to fail using a method of hoop stress analysis.
- detailed reviews of cathodic protection results;
- reviews of repairs that have been recently undertaken on the pipeline to identify any threats to integrity; and
- reviews of environmental factors such as any land slippage around the pipeline, recent works or stray currents from entities such as railways or other factors which could prove a risk to the integrity of the pipeline.

GasNet forecasts that it will require MAOP assessments for around 8 pipelines per annum over the Third Access Arrangement Period, at an estimated time of 5 days per assessment. GasNet has accordingly included an amount of $25,600 per annum for each year of the Third Access Arrangement Period within its Non Capital Cost forecasts for the MAOP assessments.

8.0 Increased costs for infrastructure patrols

Section 6.2.1 of AS 2885.3 requires that:

> "*Pipeline surveillance shall be carried out by the operating authority to ensure a pipeline is free from identifiable leaks and to identify any new or changed threats to the pipeline, particularly any unnotified external interference near the pipeline".*

Section 6.2.1 further states that:

> "*For a pipeline that is not regularly used, a patrol at frequent intervals may be maintained during use only, provided the line is isolated from sources of pressure when not in use. An annual patrol is required as a minimum.*
>
> *For a pipeline in regular or continuous use and provided the observer can clearly identify the pipeline and observe all the surveillance criteria (see [section] 6.2.2), the type of surveillance shall be by at least one of the following:*
>
> *(i) Foot patrols.*
>
> *(ii) Vehicle patrol.*
>
> *(iii) Aerial patrol.*
>
> *(iv) Watercraft for underwater pipelines."*

Section 6.2.2 notes that an active additional role must be taken by GasNet when a pipeline is disturbed by an external party, such that:

> "*Corrective action shall be initiated immediately a condition requiring such action is detected.*
>
> *Particular attention shall be given to excavation, boring activities, including the use of an auger, and drains or ditches that are maintained and cleaned by an independent party."*

This means that where there is a disturbance by an external party near GasNet's network a GasNet employee will attend the site whilst the work is being undertaken to ensure that the work does not threaten the safety of the pipeline. GasNet discharges its responsibilities in relation to regular pipeline patrolling and responding to external disturbances or activity through arrangements with skilled workers who live near its pipelines and facilities throughout Victoria. The proximity of these workers is of critical importance to GasNet, as it allows rapid response to issues such as digging or trenching which is being undertaken in the vicinity of pipelines, and also ensures that the workers can maintain relationships with the parties which are most likely to do damage, or are responsible for reporting damage or potential damage to GasNet's assets. These parties include property owners, utilities, contractors or Councils.

These disturbances are much more common in metropolitan areas due to the higher level of construction activity there. Construction activity is growing both as a result of expansion of the metropolitan areas and growth of high density areas within the metropolitan area. GasNet's pipelines are located close a number of high growth areas such as Caroline Springs and Sunbury. This has lead to a significant increase in the workload of pipeline patrollers. It is anticipated that the increased workload will require an additional pipeline patroller resulting in an increased cost to GasNet of $60,000 per annum.

9.0 Increased Compliance Costs

9.1 Regulatory accountant

The current regulatory reporting obligation on a Service Provider is simply to submit a ring fencing report.

It is clear from the tenor of the current MCE reform process that there will be an increase in reporting requirements in the Third Access Arrangement Period. The Expert Panel recommended that the rules require Service Providers to:

- provide for annual reports of regulatory accounting information; or
- provide for periodic reports of non financial information relevant to the AER's regulatory functions.

Both of these approaches would be possible under the Exposure Draft of the new National Gas Law.

This would result in an increased workload, particularly in the areas of:

- preparation of regulatory compliance reports, including regulatory accounts, ring-fencing reports, cost allocation reports and other issues that may be covered by future AER guidelines; and
- responding to issues raised as a result of regulatory compliance reports and submissions.

Currently the preparation of regulatory accounts and reports is undertaken by GasNet's management accountant. However, when the new rules are put in place the workload is sufficient that it will require the employment of a regulatory accountant.

The Regulatory Accountant will be responsible for:

- the design and maintenance of the regulatory accounts;
- preparation of reports to the regulator;
- maintenance of the Regulatory Asset Base model; and
- organising and preparing for external audits of the regulatory accounts.

It is also envisaged that GasNet will be required to submit to external audit of its regulatory accounts under the new rules. Based on the cost of external audit of the financial accounts this is expected to cost $30,000 per annum.

Based on “Market Remuneration in the Utilities Sector prepared by Geoff Nunn and Associates in association with the National Remuneration Centre” (April 2006) the market salary for a regulatory accountant is $100,000 per annum (including non salary labour costs).

9.2 Enterprise risk manager

The Financial Services Reform Act Compliance Plan (dated 2003) requires certain responsible officers to complete monthly and quarterly checklists and ensure that an internal bi-annual audit and external audits of compliance are conducted.

In order to comply with this requirement, GasNet has identified the need for a new role for an Enterprise Risk Manager. This person would have the following duties:

- create and oversee the Enterprise Risk Management Framework (ERM), which will be a database of all GasNet’s compliance obligations;
- on-going review of strategic, operational, compliance/reporting objectives, risk appetite and tolerances;
- oversee the maintenance of an enterprise-wide system that integrates existing policies, procedures and standards with regulatory obligations;
- develop risk management assessment procedures that engage staff at all levels of the organisation and promote a commitment to continual improvement;
- establish an internal audit programme aimed at determining whether the ERM framework has been properly implemented and maintained;
- oversee the compilation and periodic review of the risk register; and
- communicate the status of ERM initiatives to the Regulatory Compliance and Audit Committees of the Board.

Currently, each of GasNet’s departments has its own procedures for complying with various obligations, much of which is not audited because no one has systematically analysed the risks associated with all activities. The role of the Enterprise Risk Manager would be to adopt a more holistic approach that pulls together and documents all procedures with more comprehensive reporting and checking.

The need for someone to fulfil this function is further reinforced by the significant growth in the legal obligations placed on GasNet. GasNet has extensive compliance obligations under a range of Acts, regulations, standards, codes and other regulatory requirements, such as:

- health and safety legislation applying in Victoria;
- AS 2885;

- accounting standards in regard to financial reporting (Australian Accounting Standards), which are frequently amended or added to (for example, AASB 7 which was introduced in August 2005 and will apply to GasNet from 1 January 2007);

- improvements in best practice in regard to risk identification and management; and

- environmental protection legislation.

A report by AMR[7] research found that 46% of companies are expected to implement risk management technology in the next 12 months. The report also found the primary cost of risk management is wages.

Reporting to the General Manager Victoria this new role is responsible for implementing a robust, coherent risk and compliance framework across GasNet. The risk manager will have overall responsibility for rolling out policies and procedures and ensuring they are embraced fully. This is a broad role covering training, regulatory issues, systems, quality control and ensuring continued best practice in order to add value across the organisation.

Based on market remuneration data for the utilities sector prepared by Geoff Nunn and Associates in association with the National Remuneration Centre (April 2006) this new role is expected to cost $140,000 per annum (including additional non salary labour costs).

[7] "Risk technology spend to grow this year", Risk Management Magazine, January 2007, Issue 36.

10.0 Measures to Counter Effect of Ageing Workforce

GasNet, like other pipeline companies, is facing a shortage of skilled labour and engineering support for its pipeline and facilities operations and maintenance works. This shortage exacerbates the problem of an ageing workforce, which requires careful and ongoing management by GasNet, particularly in:

- managing impacts on service provision, consequent to the retirement of skilled managers and field staff. Succession planning has not been a driver of activity in the pipeline industry over the past twenty years, with the focus instead on microeconomic reform and efficiency; and

- retaining, recruiting and training workers to replace those exiting the workforce.

The issue of an ageing workforce is especially evident in the energy sector which is characterised by an older age distribution and a skills shortage in a period of sustained demand growth and growing customer expectations. A recent study of the Victorian Energy Industry Workforce by Buchan Consulting[8] examined some broad indicators for the energy sector and found:

- vacancies are at their highest level since June 1990;

- average hours worked in the energy sector in Victoria have increased from 39.7 hours in 1994 to 44.7 hours in 2004;

- older workers are working the longest hours with those aged 55-59 working an average of 52.9 hours a week;

- average weekly earnings in the energy sector (electricity $1081, gas $1345) are substantially higher than the average for all industries ($900); and

- wage rates are rising nationally across the sector, as energy companies and contractors seek to recruit in a tight market[9]. The study found that age is a major factor impacting on the workforce and noted that the share of the energy workforce aged 45 years and over increased from 22% in 1994 to 42% in 2004 while those aged below 35 years declined from 45% to 29%. It also found that engineers, technical officers and supervisors are the positions worst affected. In the gas sector, the study identified technical officers / supervisors as having the oldest age profile with 46% being over the age of 45 years[10].

GasNet faces these issues to a greater extent than other pipeline operators in Australia because it does not outsource its operations and maintenance activities. GasNet has adopted a strategy of maintaining core expertise in-house as it allows it to:

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[8] Buchan Consulting, *Emerging Issues for the Victorian Energy Industry Workforce, Final Report*, 2005.

[9] Page 3.

[10] Page 51.

- maintain control over the quality of work being undertaken which is essential in the gas industry;

- control the cost of core services. This is particularly important in the current environment where there is a shortage of contract labour available;

- plan and control the timeliness and delivery of services;

- retain corporate knowledge and ensure continuity. This has inherent efficiencies as it eliminates the time taken by successive contractors in familiarising themselves with GasNet's network and facilities; and

- control over succession planning and training.

GasNet therefore relies on its highly experienced team of technicians and engineers to provide services in its areas of pipeline construction, maintenance and facilities.

GasNet expects:

- 31% of its employees to retire over the next ten years, with 34 of a total of 108 employees currently over the age of 50 years;

- 20% of it's facilities management group to retire over the Third Access Arrangement Period, with six of a total of 29 staff members within that group being over the age of 56 years; and

- 50% of its engineering staff to retire over the next ten years, with seven out of a total of 13 staff within that group over the age of 50 years.

The Third Access Arrangement Period, therefore, marks the start of the impact of the ageing workforce on GasNet's business. The combined effect of an ageing workforce, a chronic skills shortage and strong growth in the energy sector means that labour market conditions are likely to tighten, at least over the medium term.

GasNet has a relatively small workforce of approximately 100 FTE employees. This means that GasNet does not have a diverse skill base that would enable more experienced employees to take time off from productive activities in order to focus solely on training new employees.

Therefore, GasNet needs to have an overlap between the new employee commencing their job and the existing employee retiring. This enables the more experienced employee to train the recruit in the requisite skills while still fulfilling their roles.

GasNet believes that it cannot take a passive approach to staff recruitment and retention. Further, as the contract market is also facing similar constraints, GasNet believes that these costs will also rise over the medium term and cannot be relied upon for cost effective alternatives to in-house resourcing.

GasNet's current intake, which is part of the 2006 base expenditure, is designed to allow for normal turnover of staff. If this is maintained then GasNet believes that it will experience a widening gap in the level of employees that it requires, and that which the market will provide. The implications of a steady stream of retirements in addition to normal turnover are that a step change in the level of recruitment is required.

The serious impact of under-investment in recruitment and training was emphasised in an independent review of the Queensland electricity distribution network conducted in 2004 which found:

> *Both distributors have an ageing field workforce. There is a shortage in Queensland and nationally of qualified electricity field workers. While it may seem an attractive short term financial option to reduce amounts spent on recruiting and training the distributors' workforces, the longer term repercussions are very serious. The Panel believes that the position has been reached where a major risk is faced if steps are not taken immediately to invest more in recruiting and training the workforce of the future.*[11]

There are two components to the scope change sought by GasNet for the Third Access Arrangement Period, being:

- recruitment costs and salaries for additional staff; and
- training and accreditation costs, including staff, facilities and materials for the additional employees.

10.1 Apprenticeships and Graduate Engineers

Given the anticipated loss of experienced staff as the workforce ages, GasNet will expand its recruitment of new graduates and apprenticeships over the Third Access Arrangement Period. This necessarily involves inefficiencies and some duplication of work. GasNet estimates additional costs of approximately $150,000 per annum.

10.2 Investment in Training

Also related to the issue of replacing and supporting an ageing workforce is the issue of training. GasNet is expecting to see a dramatic increase in its training budget as it brings in new employees to fill the roles of those employees who are retiring combined with training associated with changes in roles that will be required for aging workers.

Over the Third Access Arrangement Period GasNet also believes that it will face an increased obligation to train staff under its Enterprise Bargaining Agreement (the next agreement will be finalised in December 2008) and the Safety Case.

The increased level of training activity is, in part, a consequence of the chronic skills shortage currently being experienced across the energy sector and the need to offer competitive employment terms and conditions to attract and retain staff.

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[11] Detail Report of the Independent Panel, *Electricity Distribution and Service Delivery for the 21st Century,* July 2004, page 23-24.

GasNet has forecast that two thirds of its current workforce will attend at least one additional training course per annum at a cost of $1,500 per course, or around $100,000 per annum in total over the regulatory period.

11.0 Increase Cost for Odorant

GasNet Australia is required to add odorant to natural gas as a safety measure. GasNet organizes its purchase of odorant through a tender process every five years.

On 29 December 2006 GasNet's supplier of odorant stated that there would be a 20% increase in the cost of odorant effective from 1 January 2007 and that this would be followed by another increase late in 2007. GasNet's understanding is that this second increase will also be of the order of 20%.

The large price escalation is the result of the closure of one of three global production facilities, and there being a worldwide shortage of odorant.

Volumes of odorant are also expected to increase in line with increases in the volume of gas sales. The current value of odorant consumed in 2006 was $151,536. With the 20% increase as of 1 January, the follow up increase in late 2007 and increased volumes, this is expected to rise to $229,599.

12.0 Hazardous Area Review

The *Electrical Safety Act 1998* (Vic) mandates that AS 3000 – Electrical Wiring Rules be complied with for all electrical installations.

The *Electrical Safety Regulations 1999* (Vic) require that low voltage (typically 100 to 600 volt electrical installations) have a certificate of electrical safety issued on completion of works and in some cases this requires inspection by a licensed electrical inspector. The Regulations also require that extra low voltage hazardous area installations be compliant with standards even if they fall outside of the requirements for inspection.

AS 3000 references hazardous area installations and requires that such installations be in compliance with the AS 2381 relating to installation standards.

GasNet's hazardous area installations must be in compliance with the installation standards that were applicable at the time of installation. However, in line with industry practice, GasNet complies with current standards wherever possible.

Where dossiers, certificates or records do not exist or cannot be created from available documents, those parts of the installation that are not compliant must be brought to current standards which may mean special assessment by a competent inspector or replacement.

GasNet is proposing to undertake a hazardous area inspection project to produce a site verification dossier for each of the GasNet sites that have electrical equipment installed within hazardous areas. The production of the verification dossier requires detailed field inspection work documenting the details of all the electrical equipment that are located within the hazardous areas.

Once the site verification is completed, the inspection cycle must be maintained, typically once every 3 years depending on the protection method used by the equipment. The cost of the on going inspection work is expected to be a significant addition to the current operating budget.

The initial cost of establishing the database is being capitalized, however the ongoing cost of reviewing all assets on a 3 yearly basis and updating the database is expected to amount to the work of a full time employee at $80,000 per annum (including non salary labour costs).

GasNet Access Arrangement Submission (Schedules & Attachments)

Attachment E - SAHA on asymmetric risks

SAHA INTERNATIONAL

GasNet

Self Insurance Risk Assessment

27 April 2007

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DISCLAIMER

Saha International Limited (Saha) has prepared this report taking all reasonable care and diligence required. This report attempts to quantify the self-insured risks faced by GasNet in relation to their Gas Transmission business. The proposal document (and accompanying correspondence) should be read to provide a clear understanding of the terms of reference and the limitations of the report.

In completing this review we have relied on documents and information provided to us by GasNet and third parties for the purpose of our review. Saha has not independently audited the information provided by GasNet or third parties for accuracy as it is beyond our scope. It should be noted that if any of this information is inaccurate or incomplete, this report may have to be revised.

While Saha has used all reasonable endeavors to ensure the information in this report is as accurate as practicable, Saha, its contributors, employees, and Directors shall not be liable (whether in contract, tort (including negligence), equity or on any other basis) for any loss or damage sustained by any person relying on this document whatever the cause of such loss or damage.

26 April 2007

Mr David Whitelaw
Regulatory Affairs Manager
GasNet Australia
180 Greens Road
Dandenong VIC 3175

Dear David

Valuation of self insured risks

Please find enclosed our report for your consideration. We look forward to discussing our findings with you and your colleagues.

Please contact us if you have questions.

Yours sincerely

Kha Truong	Julie Evans
Saha International	Fellow of the Institute of Actuaries of Australia

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EXECUTIVE SUMMARY

Saha International's quantification results for the self-insured risks requested by GasNet are outlined in Table 1-1.

Table 1-1 – Summary of Self Insurance Risk Premium for Gas Quantification

Risk Premium - Gas Transmission	Annually ($)
Uplift Risk	65,000
Human Resources Risk	32,000
Fraud Risk	52,000
Insurer's Credit Risk	1,600
Bomb Threat and Extortion Risk	1,400
Key Person Risk	37,500
Total Risk Premium	**$189,500**

In addition to the above risk premium estimates, Saha International recommends that GasNet seeks the following amendments to the self insurance cost pass through provisions:

- Include Asbestos risk; and
- Amend the counter party credit risk (under the current provision) to include counter party default of GasNet contractors for maintenance and construction contracts. The provision should also be amended to allow for financing costs associated with the timing between the actual default and when the funds are received by GasNet under this provision.

The annual self insurance risk premium of $190,000 represents about 14% of GasNet's total insurance premium cost via external insurers.

1. INTRODUCTION

1.1 Introduction and Scope

GasNet is in the process of preparing an application to the Australian Energy Regulator (AER) for the regulatory price reset covering the period 2008 – 2012. As part of this application GasNet has engaged Saha International to undertake a valuation of its self-insured risks for its Gas Transmission business as part of their reset applications.

In estimating the self-insured risks faced by GasNet, Saha International has assumed that the current self-insurance cost pass through mechanisms in the current Access Arrangement will continue in the next regulatory period. This report will need to be revised if this assumption is not valid.

The risks identified in this report are in respect of the regulated business. The risk premium estimates in the report are in current 2007 dollars, unless stated otherwise.

1.2 What is a self-insured risk?

Self-insured risk can be related to an approach where the risk of a negative event is carried entirely by the company, and it may also refer to the residual risk carried by a company before/after an insurance policy's excess, deductible or limit takes effect. Deductibles require the insured to pay the first portion of any claim. They are generally included in policies to encourage better risk management and to reduce an insurer's exposure to small claims (an administrative burden relative to claim size).

The occurrence of a self insured risk would result in a loss on GasNet returns when it would not be covered by the company's insurance policies due to limit and exclusions or insufficient funds set aside for self-insurance purposes. This would result in GasNet receiving a lower than intended regulatory return because the annualised financial impact (when negative event occur) represents a real cost to GasNet.

In some cases GasNet would be able to obtain insurance for the self-insured risks we have valued in this report. However, sometimes this may not be feasible or efficient. Valid reasons for GasNet limiting the level of insurance purchased from private insurers or re-insurers include:

- GasNet believes the quoted insurance premium is excessive given the underlying risk level;
- the required insurance is not readily available;
- GasNet has sufficient resources to withstand the risks in question (for example, risks within the insurance 'deductible');
- GasNet has accepted an attractive premium on a 'standard' insurance policy which includes a range of exclusions, and the cost of 'writing back' the exclusions exceeds GasNet's perceived value of the excluded risks; or

- the insurer requires GasNet to bear a reasonable share of each claim to incentivise it to manage its risks more effectively.

The efficiency of decisions taken around self-insurance by some utility businesses has been recognised in recent Australian regulatory decisions, where:

- the ACCC approved an allowance for self-insurance in the Powerlink transmission network revenue cap (2006), GasNet access arrangement (2003) and the SPI PowerNet revenue cap (2002); and

- in its *NSW Electricity Distribution Pricing 2004/05 to 2008/09, Final Report* (June 2004) IPART and the ACCC allowed EnergyAustralia self-insurance costs for the regulatory period.

While GasNet has insurance cover for many risks (e.g. public liability and material loss of assets) there remains a range of risks for which GasNet is not currently explicitly insured, for reasons such as those listed. All efforts to mitigate risk internally are taken, but some residual risk is present, leading to costs borne by the company should a negative event occur.

This is of particular concern for those events which have a low probability of occurrence – and thus are not specifically forecast to occur – but represent a very high (negative) impact on the business and/or customers should they occur.

The scope of the study was to quantify the key risk events identified during our investigations and estimate an equivalent annualised self-insurance cost for them.

1.3 Methodology for the Valuation of Self-Insured Events

Our self-insured risks valuation is carried out in two phases whereby phase 1 primarily focused on the identification of risk events, in particular risks outside of GasNet's normal operation and maintenance control. Phase 2 involved the detailed quantification of the risk events identified under current insurance conditions.

Phase 1 of the study was prepared following a number of meetings with GasNet staff and review of documents provided for the study. In phase 1, Saha International have worked with GasNet staff to identified the risk events, which may require further analysis, and provided a preliminary financial impact estimate for the events with respect to magnitude of exposure.

This report constitutes phase 2 of the project and this study provides a comprehensive valuation of GasNet potential liabilities if the risk events were to occur during the regulatory period. The valuation involves a more detailed quantification and justification of the initial estimates made in Phase 1.

In Phase 2, Saha International have developed a methodology to analyse each event as they are different depending on type, impact on GasNet and the information we can source for the event. The basis of our approach to quantify the risk premium is to multiply the following two quantities:

- The estimated annual probability of that event occurring;
- The estimated financial consequences associated with that event occurring;

The estimates of probabilities and financial consequences are derived from a variety of means. We have based our estimates from the information we received from GasNet, market information, information from other jurisdictions, statistics/data from reputable resources and our experience in the utility industry. Therefore, the estimates necessarily involve the use of professional judgement.

The detailed methodologies for each of the risks is described in the individual risk event sections of the report, as the methodologies adopted were dependant on the risk and the data available to analyse the risk.

1.4 Reliances

In developing our views we have relied on information provided by GasNet and publicly available information (qualitative, quantitative, written and verbal) and our discussions with GasNet personnel. We have not independently verified or audited the data but we have reviewed it for general reasonableness and consistency. It should be noted that if any data or other information is inaccurate or incomplete, this report may need to be revised.

Where applicable, references have been given as to the source of the data and technical assumptions.

1.5 Limitations

This report has been prepared for GasNet for the purpose stated in the Introduction and Scope section of the report. No other use of, or reference to, this report should be made without prior written consent from Saha International ("Saha").

The risks quantified in this report are infrequent in nature and therefore there may be a lack of historical information. This combined with the future uncertainty makes it impossible to quantify the self-insured premium with any certainty. Even though we have calculated the risk premiums based on the information provided to us as well as our view on the likely future experience, it is likely that the actual experience could be considerably different from our estimates.

The self insured risks in this report do not represent the complete list of risk faced by GasNet. Self insured risks which are covered by the current self insurance cost Pass Through provision and risks relating to the non-regulated activities have been excluded from this report.

Any queries on the meaning of any statements in this report should be referred to Saha. While due care has been taken in the preparation of the report, Saha accepts no responsibility for any action which may be taken based on its contents.

The statements in this report represent the results of calculations using assumptions and data from GasNet and public sources. As such these statements and any conclusions that may be drawn from them do not represent the advice of Saha. Saha accepts no responsibility for any use made of these statements.

1.6 Report Structure

This report is structured as follows:

1. Introduction;
2. Uplift Risk;
3. Human Resources Risk;
4. Asbestos Risk;
5. Pipe Corrosion Risk;
6. Fraud Risk;
7. Insurer's Credit Risk;
8. Contractual Risk;
9. Bomb Threat and Extortion;
10. Key Person Risk;
11. Appendices.

2. UPLIFT RISK

2.1 Introduction

Uplift charges are the mechanism used to recover the cost of ancillary payments from GasNet and/or Market Participants.

GasNet is liable for uplift charges if it fails to meet its obligations under the Service Envelope Agreement (SEA) with VENCorp and, as a result, the system experiences a constraint. The uplift charges will reflect the cost impact of a reduction in system capacity caused by failure of GasNet in meeting its obligations under the SEA.

The SEA requires GasNet to provide defined gas transportation services and make available the defined gas transmission system to VENCorp at all times in accordance with requirements of good operating practice. The SEA provides for reductions in capacity due to appropriately approved maintenance programs and other applicable operating conditions.

2.2 Current Mitigation Strategies

Saha understands that uplift risk is not currently insured by GasNet. GasNet can most effectively minimise its risk by ensuring that all obligations under the SEA are complied with. This includes adequate maintenance regimes that are consistent with good operating practice.

The current SEA limits GasNet's liability to the lower of:

(i) $20 per GJ
(ii) $1 million per calendar year.

The current SEA expires on the 11th December 2007. However Saha understand that a new SEA has already been signed with an unchanged liability limit.

2.3 Past Experience

GasNet has not been liable for any uplift charges since the inception of the market. Although uplift charges have been levied against Market Participants (Retailers, Traders and Market Customers) these arise from events not related to reductions in system capacity and hence are not directly relevant to estimating GasNet's potential liability. However, GasNet has had a number of minor compressor station related incidents which had the potential to result in a minor congestion event.

2.4 Risk Factors

The key components relevant to GasNet's exposure to uplift charges include:

- The probability of ancillary payments in the Victorian gas market due to failure by GasNet to meet obligations under the SEA;

- Gas prices at the time of any ancillary payment resulting from GasNets failure to meet obligations under the SEA.

Risk factors affecting GasNet's uplift liability include:

- The dynamics of the Victorian system require more compressor cold starts and shutdowns than typical transmission systems. This unusual duty cycle increases the risk of compressor failure causing GasNet to breach the SEA;

- The separation of system operation and maintenance duties between GasNet and VENCorp may lead to inefficiencies in providing a coordinated response to contain emerging problems; and

- Possibility of a legal challenge disputing the suitability of GasNet's maintenance practices where large congestion uplift payments have been levied on other market participants. An adverse judgement could result in a reallocation of uplift liability to GasNet.

The Victorian gas market has undergone a number of changes in recent years. New sources of gas have been introduced that have resulted in an increase in price volatility and increased constraints in the system. There is higher utilization of the Western Underground Storage and increased usage of gas for electricity generation. The market has recently moved to a higher granularity of pricing with prices being set at four hour intervals during the day and increased forecasting requirements for Market Participants.

The probability of ancillary payments due to a failure by GasNet to meet its obligations is unlikely to be materially affected by these changes. The increase in the complexity of the Victorian gas market affects the operation (VENCorp) rather than the maintenance of the transmission system. There may be some change required to maintenance programs to ensure their suitability to the current system. However, as long as GasNet focuses on performing its obligations under the SEA there should be no additional increase in incidence of ancillary payments due to GasNet than has applied in the past.

The amount of an ancillary payment will be affected by the bid gas prices at the time of constraint. New sources of gas, new Market Participants and increasing sophistication of market bidding have led to increasing price volatility. The new wholesale market with four hourly price intervals will result in higher prices in peak demand periods. As the probability of constraint is highest in peak demand periods, the gas price is likely to be higher at times of constraint with the new wholesale market.

2.5 Overall Risk Premium

The overall risk premium has been based on two scenarios resulting in uplift charges allocated to GasNet, namely a major congestion event and a minor congestion event.

The probabilities and values assigned to the scenario's have been based on high level estimates due to limited historical data.

A major congestion event has been defined as a failure by GasNet to supply 100TJ of SEA capacity. The cost of meeting demand using higher priced supplies will typically result in uplift costs per GJ in excess of $10. Hence in this case we would assume that the uplift charge would be capped at $1 million as defined in the SEA. We believe that the likelihood of a major congestion event is low but possible and have assumed that one occurs every twenty years.

A minor congestion event has been defined as a failure by GasNet to supply 10TJ of SEA capacity. The cost of meeting demand using higher priced supplies is assumed to involve uplift costs of $7.5 per GJ. This represents a potential LNG cost or supply from the Western Underground Storage as these are typically the first to supply in times of congestion. While currently these supply sources are bid into the market at prices lower than $7.50/GJ we have assumed that the bid prices for these supply sources will rise in the future due to a more dynamic four hourly market. We see this higher price as being potentially driven by two key factors:

- The scarcity value of these supply sources (in particular, LNG) in times of congestion; and
- Opportunity value as market participants who have access to these supply sources seek to maximise returns from their investments.

We have assumed that a minor congestion event occurs on average once every 5 years.

The assumptions used are based on Saha International's high level assessment of the risk together with discussions with GasNets regarding possible scenarios.

The estimated risk premium is calculated in Table 2-1 below.

Table 2-1 – Uplift Self-Insurance Risk Calculation

Scenario	Quantity(TJ)	Price ($/GJ)	Uplift Liability	Frequency	Risk Premium Estimate ($ pa)
Major Event	100	>10	Limited to $1M	5%	$50,000
Minor Event	10	7.5	$75,000	20%	$15,000
Total					$65,000

Therefore, the estimated risk premium for GasNet's exposure to uplift liability is $65,000 pa.

3. HUMAN RESOURCES RISK

3.1 Description of Risk

This refers to the risk of GasNet's operations being adversely affected by HR issues. For the purpose of our analysis, we will only focus on industrial relations and disputes risks as key person risks are covered in Section 10 of the report.

Industrial relations can be regarded as the relationships and interactions in the labour market between employers and employees (and their representatives), and the intervention in these relations by governments, government agencies and tribunals (e.g. the Australian Industrial Relations Commission).

In the event of poor industrial relations due to workplace disagreement, disputes arise. An industrial dispute is a disagreement over an issue or group of issues between an employer and its employee, or a group of employees, which results in employees ceasing work or imposing restrictions on the company's operations (eg. banning overtime).

The causes of disputes usually stem from disagreements in relation to remuneration, employment conditions, health and safety, job security, managerial policy and union issues. Generally, industry disputes can be categorised into:

- Individual disputes, which are relatively easier to resolve by the employer; or
- Group disputes (usually as a result of 'poor' Enterprise Bargaining Agreement process), which can result in employees ceasing work in the forms of:
  - Strikes, which are a withdrawal from work by a group of employees; and
  - Lockouts, which are the refusal by a group employees to permit some or all other employees to work.

A group dispute will typically be more costly for the firm, but will occur less frequently than individual disputes.

3.2 Historical Incidents

Since GasNet was established in 1995, no significant industrial actions, such as bans, strikes and lockouts, have been taken by its employees. During the first Enterprise Bargaining Agreement (EBA) negotiations, bans were placed on phone answering in some sections of the organisation, but they did not result in any measurable cost impact or significant operational consequences.

In terms of individual disputes, three previous disputes have occurred, resulting in settlement payments being made by GasNet to the claimant, in order to avoid going to the Industrial Relations Commission (in two cases) and the Equal Opportunity Commission (in one case). The average settlement amount for these three cases was about $18,000 (inclusive of legal costs). In addition, an ex gratia payment of $30,000 (inclusive of legal costs) was made to an employee who was found to be incapable of performing his previous duties due to a work related injury. The payment was made in return for a release relating to the termination of his employment.

Also, GasNet has noted that it may be subjected to industrial actions or activities taken by individual employees and contractors or groups of employees involved in construction projects related to their assets, which may result in delays and increased overall project costs. Notwithstanding this, GasNet has indicated that additional costs relating to industrial actions on capital projects would probably be absorbed into their overall project costs. Therefore, this has been excluded from the analysis.

Lastly, GasNet is currently going through an integration process due to the recent acquisition by the Australian Pipeline Trust. In addition, GasNet will be going through the process of negotiating a new EBA in 2008. Whilst generally, this represents a significant potential HR risk going forward, it is not possible to identify, with any certainty, the potential industrial actions during and post negotiations.

3.3 Mitigations Strategies and Associated Costs

GasNet adheres to the following IR strategies to ensure that a good relationship is maintained with their employees:

- Maintain open communications with employees, union officials and employee representatives;
- Negotiate in good faith to avoid disputes;
- Avoid implementing radical changes to existing industrial agreements or practices;
- Whenever possible, settle disputes at the earliest opportunity;
- Always seek legal advice in relation to potential disputes and claims to ensure that they are acting in accordance with the law and not exposing themselves to undue risks; and
- Engage specialist consultants to advise on industrial relations matters and to assist with negotiations.

Saha International understands that GasNet has not made provisions for amounts that may be paid for legitimate claims or to resolve industrial disputes in its forecast O&M budget.

3.4 Detail Quantifications

3.4.1 For Group (Major) Disputes

Saha International has based its analysis on information obtained from the Australian Bureau of Statistics (ABS) spanning a twelve year period from 1994 to 2005. Table 3-1 below summarises the average working days lost per thousand employees for 'other' industries, which includes the following business sectors:

- Agriculture, Forestry and Fishing;
- Electricity, **Gas** and Water Supply;
- Wholesale and Retail Traders;
- Accommodation, Cafes and Restaurants;
- Finance, Insurance, Property and Business Services;
- Government Administration and Defence; and
- Cultural, Recreational, Personal and Other Services.

Table 3-1 – ABS Average Working Days Lost per Annum Due to Industrial Disputes

Australian Bureau of Statistics Working Days Lost Per Thousand Employees, By Industry											
1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
16.0	**12.0**	**17.0**	**11.0**	**8.0**	**6.9**	**8.7**	**7.1**	**8.7**	**4.9**	**10.0**	**2.2**

From the data, the average working days lost per thousand employees for the other industries category over the past 12 years is calculated to be 9.4 days. We note that the higher than average working days lost during the period from 1994 to 1997 is mainly driven by industrial disputes in the utility sector during this period.

GasNet currently employs just over 100 staff. Applying the above ABS statistics to GasNet's business suggest that GasNet will have a total of about 5 working days lost over a five year period. The information obtained from the ABS indicates that the utility and 'other' sectors grouped under this industry category are not likely to have frequent and or prolonged group disputes between employee and employer. We have assumed that a major industrial incident will occur once in every 10 years with duration of about 5 days.

In the event of a group dispute, the provision of gas to GasNet's customers is unlikely to be significantly affected. However, discussions with GasNet identified that the additional costs would include:

- Legal and advisory costs;
- Contract skeleton maintenance and operations staff[1]; and

[1] VENCorp is the systems operator. However, GasNet has a small operations team to man the control centre.

- Indirect business interruption costs due to the diversion of management time.

We have assumed that a major industrial dispute (lasting 5 working days) would result in additional costs of $250,000 based on:

- $100,000 in direct costs; and

- $150,000 (or about 0.13% of annual revenues) estimate of the business interruption cost.

The estimated risk premium for a major industrial dispute is = 0.10 * $250,000 = $25,000 pa.

3.4.2 For Individual (Minor) Disputes

Using information provided by GasNet, we assumed a 4 in 12 year probability or 0.33 individual dispute per annum. This is based on GasNet's records of three individual disputes and one ex gratia settlements since their establishment in 1995.

In terms of cost, we have based our calculations on the average of the four recorded payouts[2], which equates to approximately $16,000 per individual dispute. We did not include any legal fees/expenses, as we expect GasNet to include them in their O&M budget as per their current 2007 O&M budget arrangement.

As such, the estimated risk premium for individual disputes is = 0.33 * $21,000 = $6,930

3.5 Estimated Self Insurance Risk Premium

The overall self insurance risk premium is a function of the cost of a major dispute and a minor dispute.

= Major + Minor Dispute Risk Premium

= $25,000 + $6,930

= $32,000 per annum.

The risk premium estimate is lower than the insurance quote of $40,600 (inflation adjusted) for Employment Practices Insurance obtained by GasNet at the last regulatory reset. For, the purpose of this submission, we have adopted the risk premium estimate of $32,000 pa.

[2] ($18,000 * 3 + $30,000) ÷ 4 = $21,000

4. ASBESTOS RISK

4.1 Description of Risk

We understand that asbestos has historically been used in pipeline corrosion protection, and around valves. GasNet are potentially liable for claims related to the impact that asbestos, which was, or still is contained within its assets, has, or previously had, on the health of its employees and third parties. We also understand that concealed asbestos was recently found at the Gooding compressor station thus highlighting the possibility of this risk occurring.

According to GasNet, an Asbestos Register is held for each site. The data from most of these registers is included in an electronic Hazardous Building Materials Register, which is maintained on GasNet's intranet. These registers are updated as Asbestos Containing Material (ACM) is removed. Most of the asbestos is not friable (not easily crumbled or reduced to powder) and therefore, does not present a significant risk in its current state.

Currently, GasNet is not insured against asbestos exposures and GasNet's policy does not provide insurance coverage for the removal and disposal of asbestos. However, such work is specialised and it is anticipated that a specialist contractor would be engaged who themselves should carry insurance. GasNet has in place work practices to ensure that contractors have appropriate insurance.

4.2 Mitigations Strategies and Associated Costs

As mentioned earlier, asbestos surveys are conducted by appropriately qualified individuals to establish the presence of readily observable ACM at each site. This information is recorded on the Asbestos Register, a copy of which is maintained on site. It is a company policy that the Asbestos Register is to be consulted before work is undertaken that may involve disturbance to ACM. In addition, ACM is labelled wherever possible. The costs of performing this work are included in GasNet's routine O&M expenditures.

Asbestos audits under Part 6 of the OHS (Asbestos) Regulations Victoria 2003 are undertaken where necessary when demolition and refurbishment works (as defined in the regulations) are planned for GasNet facilities. If ACM is identified in these audits, it is removed prior to work commencing. ACM is also intended to be removed and replaced, where practicable, even where "demolition and refurbishment" works do not apply.

Based on GasNet's projected work programs, a provision of $100,000 per annum could be made for the next 5 financial years beginning July 2007.

4.3 Cost Pass Through Provision

Asbestos is a proven health hazard but risk wise, exposure can still be considered a low probability event that has wide ranging consequences. In the United States, asbestos litigation is the longest and most expensive mass tort, involving more than 6,000 defendants and 600,000 claimants[3]. Current trends indicate that the rate at which people

[3] http://www.abanet.org/poladv/priorities/asbestos.html

are being diagnosed with the disease is likely to increase over the next decade. It is estimated that the total costs of asbestos litigation in the US alone is over $250 billion[4].

In Australia, company shareholders of James Hardie agreed on a new compensation package worth more than US$4 billion over 40 years[5], which is an equivalent to US$100 million per annum. The annual asbestos litigation payout is approximately 18.15% of James Hardie's profits (approximation is based on James Hardie's reported US$550.8 million gross profit in 2006).

Our research shows that stand alone (individual) payout can be $335,000[6].

From our experience, asbestos is a significant legitimate business risk faced by Gas Transmission companies around the world, and GasNet is no exception. Any estimate of the expected cost of asbestos related risk is necessarily subjective and a wide range of possible values is feasible, therefore, we recommend that GasNet seeks a specific cost pass through provision related to asbestos related risk.

[4] The Economist - The war on tort, 26 Jan. 2005
[5] ABC News Online, Updated Thursday February 15 2007
[6] The Australia Financial Review, "Asbestos Victims Hit By Delaying Tactics", pg 57 Wednesday 4 April 2007

5. PIPE CORROSION RISK

5.1 Introduction

Gas pipes can be at risk of corrosion due to both ageing and / or the location or environment in which the pipe is situated (e.g. stray electrical current running from engines such as trams or trains, acidic soil can be a risk to buried gas pipes, etc.).

5.2 Self Insurance Risk Premium

We do not believe a self insurance premium is required for this risk as the capital cost of replacing the asset (and any third party liability costs) in the event of a major pipeline incident would be addressed through other regulatory mechanisms.

6. FRAUD RISK

6.1 Description of Risk

There is currently no precise legal definition of fraud. For the purposes of reporting fraud the following crimes fall within the context: Theft, False Accounting, Bribery and Corruption, Deception and Collusion.

The majority of the largest frauds reported by organisations were detected by employees, or identified through the organisation's internal control system. Fraud was detected by an organisation's internal control system in 19 percent of cases reported in 2006[7]. It is significant that in 16 percent of cases reported the largest single fraud was detected by an outsider, including customers and suppliers[8].

The deliberate nature of fraud can make it difficult to detect and deter. Preventative controls and the creation of the right type of corporate culture will tend to reduce the likelihood of fraud occurring while detective controls and effective contingency planning can reduce the size of any losses.

6.2 History of Relevant Incidents

Both globally and in Australia, numerous incidents of fraud have occurred in recent years. More specifically, Saha International is aware of a number of utilities businesses in Victoria and Australia that have suffered from fraud related incidents over the previous five years.

However, GasNet has not advised us of any claims that have been made with respect to any significant historical fraud incident. Therefore, there will be no fraud related cost embedded within GasNet's base operating costs. It should be noted that there is a possibility of fraud occurring but remaining undetected. This implies that all incidences of fraud occurring do not equate to all incidents of fraud reported. There is a percentage of fraud occurring within organisations which remains undetected.

6.3 Current Mitigation Mechanisms

GasNet's general insurance policy excludes any loss or series of losses arising out of employee embezzlement or fraudulent acts. The absence of insurance precludes GasNet from making a claim under the current cost pass through provisions pertaining to 'insurance related events', and thus, would result in it having to fully fund any costs resulting from fraud related incident.

GasNet's mitigation strategy is to ensure that there are processes within the organisation to prevent fraud. These processes include internal accounting controls over the authorisation and approval of payments and purchases; separation of responsibilities; periodic stock takes of inventory; expenditure limits for individuals and internal/external audits. GasNet maintains a risk register with fraud risk embedded as part of their business

[7] KPMG Fraud Survey 2006
[8] KPMG Fraud Survey 2006

risk. Whilst these controls remain in place to mitigate fraud incidents, there may still be occasions where fraud causes either catastrophic or minor losses[9].

6.4 Fraud in Australia & New Zealand

In the wake of several major corporate collapses around the globe since 2001 (including several in Australia), there is a heightened concern about the potential for fraud. Financial statement fraud, the key fraud faced by organisations, contemplates the falsification of an organisation’s accounts by, for example, manipulating revenue, capitalising expenses, hiding non-recoverable loans or selectively applying accounting policies in order to give a false impression of the financial performance of a business entity or its financial position at a particular point in time.

This concern has resulted in significant legislative change around the globe, including the Sarbanes-Oxley Act 2002 in the US and CLERP 9 legislation, which became law in Australia on 1 July 2004. Much of this legislation deals with the need for greater vigilance on the part of directors and senior executives in the operation of entities they govern together with greater accountability for financial reporting.

The reported incidence of fraud suffered by Australian companies has doubled from 27,657 in 2004 to 65,000 in 2006, according to the latest findings of the KPMG Fraud Survey. Although the total number of fraud incidents reported has increased by over 100%, the value of frauds recorded in 2006 was lower than those recorded in 2004. The survey was conducted with 495 organisations within Australia & New Zealand across public and private sectors.

The industries in which the organisations that were surveyed operate are outlined in Table 6-1:

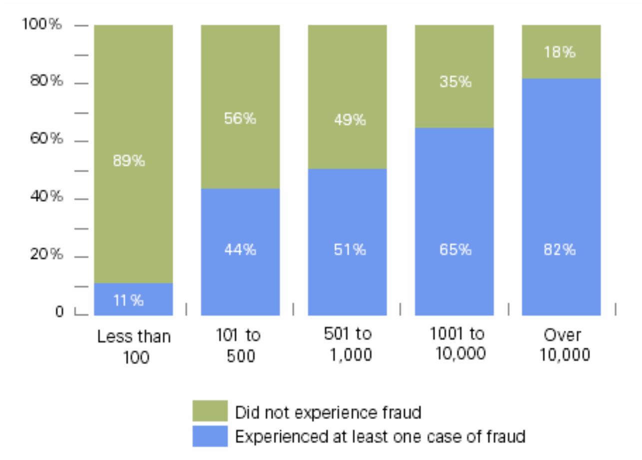
[9] Document on Gas Net Self Insurance Risks from Bruce Rose sent on 29th March 2007.

Table 6-1 – Fraud Survey Breakdown of Industries

Industry	Percentage of organisations
Power	5.60%
Building and construction	5.00%
Local government	4.80%
Mining	4.50%
Food and beverage	4.40%
Automotive	4.30%
State government	4.30%
Transport	4.00%
Insurance	4.00%
Federal government	4.00%
Consumer Products	3.80%
Health Services	3.80%
Other sectors	3.80%
Oil	3.50%
Banking	3.50%
Superannuation	3.50%
Retail	3.20%
Managed investments and funds management	2.90%
Tourism	2.60%
Chemical	2.50%
Industrial markets - other	2.30%
Financial services - other	2.30%
Software	2.30%
Education	1.90%
Consumer Markets - other	1.90%
Government - other	1.60%
Communication	1.50%
Pharmaceutical	1.30%
Real estate	1.30%
Winery	1.20%
Media	1.00%
Biotechnology	0.90%
Information, Communication, Entertainment - other	0.70%
Forestry	0.60%
Energy and Resources - other	0.60%
IT Hardware	0.40%
	100.00%

The survey concluded that the reported fraud rises proportionately with the size of the organisation. Sixty-five percent of organisations with between 1,000 and 10,000 employees experienced at least one fraud, while eighty two percent of organisations employing more than 10,000 people reported at least one fraud incident (refer Table 6-2). Lower rates of fraud were reported in smaller organisations.

Table 6-2 – Fraud Experienced Relative to Company Size[10]



This trend is consistent with the 2004 KPMG Fraud Survey which reported the results shown in Table 6-3.

Table 6-3 – 2004 KPMG Fraud Survey Results

Employees	Number of organisations	Organisations experiencing fraud (%)	Average Loss per organisation ($)
Up to 100	87	15	1,013,423
101 to 500	142	34	152,487
501 to 1000	96	48	127,107
1001 to 10,000	132	66	845,487
Over 10,000	11	100	30,755,954

Thirty-nine percent of organisations in 2006 believe that fraud is a major problem for business generally, which is down from 50 percent who believed this in 2004. In contrast, only seven percent of organisations believe that fraud is a major problem for their own organisation. This response is down from the 17 percent reported in 2004. It may suggest that fraud, although acknowledged as occurring within individual entities, involves losses that are not regarded as significant by the organisation. Alternatively, it may suggest that many organisations see fraud as a major problem within the economy, but believe that their own systems and controls are more effective than prevailing standards and are more likely to be effective in reducing fraud risk within their own organisation.

Table 6-4– 2006 Number of Frauds Detected

Number of frauds detected	Organisations (%)
1	21
2 to 10	55
11 to 50	14
51 to 1000	7
over 1000	3

[10] KPMG 2006 Fraud Survey

As shown in Table 6-5 below, similar trends were observed in 2004, with twenty-two percent of organisations reporting that at least one fraud was detected, sixty-two percent experiencing between 2 and 10 cases of fraud, while one percent of organisations reported experiencing more than 1,000 incidents.

Table 6-5 – 2004 Number of Frauds Detected

Number of frauds detected	Organisations (%)
1	22
2 to 10	62
11 to 50	7
51 to 1000	9
over 1000	1

6.5 Probability of Claim

Despite the lack of data with respect to major fraud incidents in GasNet, there is still a probability that such an incident can occur. To calculate this probability, we have relied on an examination of the fraud incidents and company liability experience available for Australian and New Zealand companies.

GasNet have informed us that they have 103 full time equivalent employees. Therefore, Saha International has based its assessment on the results of the 2004 KPMG incident data, which indicated that thirty four percent of organisations with between 100 and 500 employees experienced at least one fraud a year with an average loss of $152,487. This average would include the more significant cases in other sectors such as banks. However, this figure is lower than our understanding of the recent loss incurred by a Victorian energy business.

Saha International has assumed that the survey respondents were representative of GasNet, in terms of exposure to fraud, internal mitigation mechanisms used to detect and deter fraud, and the level of losses suffered if a fraud event were to occur.

6.6 Estimated Self-Insurance Premium – Fraud Risk

Based on the above information and the data highlighted in Table 6-3, we estimate the total self-insurance premium for GasNet's fraud risk as follows:

Employees at GasNet	Estimated incidents per annum	Average Loss per Incident $	Estimated Rsik Premium ($ pa)
103	0.34	152,487	51,846

The self-insurance risk estimate for GasNet's exposure to fraud is $52,000 p.a.

7. INSURER'S CREDIT RISK

7.1 Introduction

Insurer credit risk is faced by GasNet, where there is a possibility that its insurers may default. The effects for GasNet may be:

- The loss of the premium paid in respect of the unexpired period of cover. This is later referred to as the loss of premium paid risk; and/or

- Liability exposure, where an insurer who is unable to honour an insurance policy, leaves GasNet fully exposed to any outstanding claims (including any incurred but not reported (IBNR) claims). This is later referred to as the liability risk.

In recent years, Australia has seen the HIH collapse leave thousands of policyholders out-of-pocket. The collapse has lead to a wide range of businesses being exposed to retrospective product and public liability claims for many years into the future. This is because these types of insurance policies are traditionally written on an 'occurrence' basis, where an insured event that occurred during the year of coverage is met from that year's policy, even if the claim is made in the future.

7.2 Current Mitigation Mechanisms

As part its 2003 Access Arrangement, GasNet elected to explicitly self insure against this risk (Section 4.12 (a)(ii)). Saha has undertaken the following analysis based on the assumption that GasNet will once again self insure this risk in the 2008 Access Arrangement.

7.3 Methodology Adopted

In estimating the loss of premium risk, we have assumed that bankruptcies occur mid-way through the year, and furthermore, we have estimated the annual liability exposure risk as an insurance premium equivalent. This reflects expected loss experience. However, the exposure to loss could be considerably larger given the large insured loss limits and the fact that claims are often not settled for some years (so more than one year's claims could be outstanding).

The estimated risk premium is equal to the amounts at risk multiplied by probability of default. Probability of default was derived from the insurance companies' credit ratings. This is explained in more detail below.

7.4 Forecast of insurance premiums over the forthcoming regulatory period

In forecasting insurance premiums over the regulatory period, we have assumed that the most recent premiums paid by GasNet to each of their insurers will remain constant. GasNet's current insurance cost is $1.4m pa, with the larger providers being the American Home Assurance Company, Liberty and Lloyds of London.

7.5 Default probabilities for each Insurance provider

The credit ratings and default probabilities used in our analysis are the most recent ratings assigned to each of GasNet's insurance providers, either by Standard and Poor's (S&P) or Fitch Ratings. Refer to Table 7-1.

Table 7-1 – Standard and Poor's Default Probabilities

Table 3

Australia and New Zealand Cumulative Average Default Rates, 1989-2005 (%)

	—Time horizon—									
Rating category	**Yr. 1**	**Yr. 2**	**Yr. 3**	**Yr. 4**	**Yr. 5**	**Yr. 6**	**Yr. 7**	**Yr. 8**	**Yr. 9**	**Yr. 10**
AAA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AA	0.00	0.00	0.00	0.27	0.57	0.57	0.57	0.57	0.57	0.57
A	0.15	0.32	0.50	0.50	0.50	0.74	1.03	1.03	1.03	1.03
BBB	0.18	0.38	0.61	0.88	1.21	1.62	2.16	2.88	3.93	5.64
BB	1.30	1.30	1.30	5.50	8.45	8.45	8.45	8.45	8.45	8.45
B	3.45	10.88	16.95	21.32	23.57	23.57	26.40	32.80	40.27	48.80
CCC/C	37.50	45.83	58.33	58.33	58.33	58.33	58.33	58.33	58.33	58.33
Investment grade	0.11	0.24	0.38	0.53	0.71	0.91	1.15	1.30	1.48	1.74
Speculative grade	7.55	11.72	16.36	19.89	21.99	21.99	23.52	27.25	31.80	37.05
All rated	0.74	1.20	1.70	2.13	2.45	2.64	2.97	3.38	3.90	4.59

Source: Standard & Poor's, and Australian Ratings.

7.6 Quantification of risk premium arising from the loss of premium risk

In quantifying this risk, we have assumed that:

- Bankruptcies occur midway through the year;
- In the event of bankruptcy, GasNet will need to purchase an additional insurance policy, over and above what was in their base operating costs, to cover the second half of the year; and
- The insurance premium incurred for the second half of the year and the years beyond is the same as what GasNet included in their base O&M forecasts, therefore there is no additional cost incurred by GasNet.

Hence, the annual risk premium for the 'loss of premium paid' risk is calculated as the forecasted annual insurance premium for the respective insurance provider * average annual default probability associated with the respective insurance provider * 1/2 a year, summed over all the insurance providers. Note that the result is multiplied by 1/2 a year to take account of the assumption that bankruptcies occur midway through the year.

7.7 Quantification of risk premium arising from the IBNR (Incurred But Not Reported) risk

The IBNR risk premium attempts to quantify the liability exposure that may arise from an insurance provider going bankrupt in any one year.

In quantifying this risk, we have assumed that:

- Bankruptcies occur midway during the year;
- In the event of bankruptcy, GasNet may have outstanding claims from the first half of the year (and from previous years) that cannot be recovered from the bankrupt insurance provider;
- The insurance premium charged by the provider represents their quantification of their risk exposure during that period, along with the addition of a margin to cover costs, as well as margin to make a profit;
- The premium charged for that half of the default year is a proxy for the liability exposure during that period, as the profit margin is generally small relative to the size of the premium.

Accordingly, the estimated annual risk premium arising from the liability risk is assumed to be the same as the risk premium arising from the loss of premium risk: forecasted annual insurance premium for the respective insurance provider * average annual default probability associated with the respective insurance provider * 1/2 a year, summed over all the insurance providers. Note that the result is multiplied by 1/2 a year to take account of the assumption that bankruptcies occur midway through the year.

7.8 Risk premium calculations

As shown in Table 7-2 below, the total risk premium is calculated as the sum of the liability and loss of premium paid components.

Table 7-2 – Risk Premium Calculations for Both Scenarios

Forcast of Annual Insurance Premium	Rating	Default Probability	Risk Premium from IBNR	Risk Premium from loss of premium paid	Total Risk Premium
529,482	AA	0.00095	252	252	503
867,355	A	0.00123	533	533	1,067
1,396,837			**785**	**785**	**1570**

The annual risk premium estimate is $1,600 pa.

8. CONTRACTUAL RISK

8.1 Introduction

Contractual risk is the risk that is faced by GasNet when the terms and conditions of a contract made between a third party and GasNet exposes GasNet to some residual risk. In most cases, the contractual arrangements themselves will include appropriate penalty clauses for the contracting party, hence mitigating the risk. However, it may be unviable for GasNet to fully mitigate every risk through contractual agreements, in particular, where the cost to GasNet of mitigating that risk within the contract are greater than the benefits to GasNet of mitigating that risk. In such a case, a residual risk is borne by GasNet, which should then be passed onto customers, as this forms part of the least cost means of delivering gas transmission services to those customers.

In estimating GasNet's exposure to contractual risk, the analysis has focused on contracts relating to the regulated business. GasNet's regulated business has limited contract types. GasNet's regulated contracts comprise of Gas Transportation Deeds (GTDs) and Maintenance and Construction Contracts. The former is discussed in further detail in the following sections. In relation to maintenance and construction contracts, Saha International has analysed the standard works and supply contracts sent to it by GasNet, and believes that these appear to provide fairly comprehensive coverage to GasNet in relation to the likely risks that it would face, including, but not limited to:

- Counter-party credit risk (bank guarantees covering 10% of the price);

- Inappropriate quality (GasNet can access the bank guarantee to recover any costs, losses or damage incurred by GasNet; they can withhold 10% each Progress Payment up to a limit of 10% of the Price);

- Cost of undertaking remedial work to overcome deficiencies, which is not caused by GasNet, must be borne by the contractor, up to the end of the Defects Liability Period; and

- Time over runs (Liquidated Damages).

Notwithstanding the above, it is noted that there appear to be a number of residual risks still carried by GasNet in relation to these standard works and supply contracts, including where GasNet has to:

- Re-tender where a contractor has defaulted;

- Fix defective works post the "Defects Liability Period";

- Fix works due to GasNet defining an incorrect 'scope of works'; and

- Fix works where a contractor has defaulted, and the bank guarantee is unable to fully cover the costs.

GasNet has been unable to provide any specific information with regards to these residual risks in relation to its current (and/or expected) maintenance and construction contracts. Therefore, Saha International has been unable to quantify the aforementioned residual risks that are currently being borne by GasNet.

Saha International, recommends GasNet seeks to amend the counter party credit risk (under the current provision) to include counter party default of GasNet contractors for maintenance and construction contracts.

8.2 Counterparty Default

The main contractual risk that is faced by GasNet, in relation to their GTDs, is the risk of counterparty default. The direct cost of counter party default is covered under the Pass Through Event mechanism of the current Access Arrangement.

Under section 10.1 of GasNet's Access Arrangement, a Counterparty Default Event has been defined as

> *"The default by a Shipper in respect of an amount or amount payable by the Shipper to GasNet under the relevant Gas Transportation Deed"*[11].

Therefore, should GasNet suffer a loss due to counterparty default of a GTD contract, the loss from the event will eventually be recovered through the Pass Through provisions. However, it has been noted that the Pass Through mechanism does not appear to incorporate any financing cost associated with the delay between the time of the default and actual timing of when GasNet receives the Pass Through revenue adjustment.

8.3 Financing cost associated with a counterparty default event

Saha International analysis shows that the financing cost associated with a counterparty default event can be quite significant. In particular, if the default event was in respect of one of the three main retailers, the financing cost could be as high as $0.8m based on the following assumptions:

- $11m exposure (or about 4 months of revenues). In determining the exposure, the number of days for which GasNet may deliver gas and not receive payment has been totalled. The 4 months of exposure has been derived from the relevant sections of the GTD[12] plus an estimated 2 month period before GasNet stops delivering gas to the defaulted Shipper based on the trading terms of the GTD;

- Mid-year default;

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[11] GasNet Australia Access Arrangement, Commencement date: 1 January 2005.

[12] The 64 days of exposure was derived from the sample GTD contract by taking the sum of:
- The 30 day lag associated with invoicing for the preceding month (Section 3.3(a));
- The 24 days lag (including weekends) for the issuing of the invoice to the Shipper (Section 3.3(a)); and
- The allowance of 10 days (including weekends) for a Shipper to pay the invoice (Section 3.3(c)).

- A period of 15 months (approximate) has been assumed before GasNet can recover the loss from a contractual risk event. A substantial amount of time is required for the quantification of the default amount and application of a Pass Through provision. Since it has been assumed that the event is to occur in the middle of the year and with the end of the exposure period being the beginning of October, it has been assumed that GasNet will not have sufficient time to claim the cost of the event by the beginning of the following regulatory year. Therefore, GasNet will only be able to recover the cost in the regulatory period after that. This will result in the total time of approximately 15 months (446 days) before the cost of the event can be recovered; and

- Financing cost based on an indicative real WACC of 6%.

Saha International does not believe that a risk premium should be estimated (by applying a probability to the estimated finance cost) as the direct cost impact of counterparty default is included in the cost Pass Through provisions. We believe that the residual risk associated with the financing costs relating to a default event be allowed for explicitly within the cost Pass Through provisions.

9. BOMB THREAT AND EXTORTION

9.1 Introduction and Description of Risk

GasNet faces the risk that a malicious and deliberate act of sabotage in the context of bomb threat and or extortion is threatened to be undertaken by a third party, which in turn impacts on GasNet's ability to deliver gas, and / or, the costs associated with delivering that gas. This represents a real and material exogenous risk, with costs including, amongst other things, capital replacement costs, standby costs, time off supply and increased costs of purging the gas system. Extortion demands and bomb threats not only directly affect a company financially, but also have significant indirect consequences ranging from business interruption to legal liability, and sometimes months of confusion and distraction to the company.

With reference to GasNet's Access Arrangement[13] and its Insurance Manual[14], non terrorist related extortions and bomb threats are currently self-insured. Whereas, an extortion or bomb threat pertaining to a terrorist related event is covered off by the cost pass through provisions of GasNet's current Access Arrangement. For the purposes of our analysis, we have assumed that the current cost pass through provision related to terrorist events will be maintained in the 2008 Access Arrangement, and therefore, we have excluded extortion and bomb threats that are related the act of terrorism. We have assumed this to be:

> *"an act, including but not limited to the use of force or violence and/or the threat thereof, or any person or group(s) of persons, whether acting alone or on behalf of or in connection with any organisation(s) or government(s), which form its nature or context is done for, or in connection with political, religious, ideological, ethnic or similar purposes or reasons, including the intention to influence any government and/or to put the public, or any section of the public, in fear".*

The risk of non-terrorist related bomb threats and extortion covers, amongst other things:

- A disgruntled individual or group of individuals, bombing, attempting to bomb, or providing for a bomb hoax to be carried out, upon GasNet's assets; or

- A bombing, attempted bombing, or a bomb hoax, being directed towards a third party located within close proximity to GasNet assets, thus exposing GasNet to potential collateral damage.

GasNet is vulnerable to these risks in the running of their business even though gas infrastructure/assets are less accessible when compared to electricity transmission networks. Nonetheless, any threats or acts committed to damage GasNet's assets or injure its staff will result in:

- An increase in costs over and above those forecast in their regulatory submission, due to capital replacement costs, additional costs of having contracts on standby and increased costs of purging the system;

[13] Approved by ACCC on 15 Dec 2004 and commencement date on 1 January 2005
[14] Insurance Manual 2006 – 2007 GasNet Australia Limited by MARSH

- A possible loss in revenues over the duration of the incident and its resultant effects on the business due to time-off supply; and

- Possible compensation pay-outs to customers whose service is affected.

9.2 GasNet's current mitigation strategies

GasNet has the following programs implemented to reduce the chances of bomb threats and extortion on their gas transmission business:

- Exercise Belladonna – An annual exercise, in accordance with Part 6 of the Terrorism (Community Protection) Act 2003, including participation from GasNet, to test their ability to respond to a terrorist activity, involving the presence of the Department of Infrastructure and Victoria Police; and

- GasNet has Business Continuity Plans and Disaster Recovery Plans in place for these types of events, which describes alternative sources of equipment to replace damaged assets, plans for quick recovery of the system and minimising the impact of the event.

Furthermore, the consequence of any bomb threat or extortion is likely to be partially reduced by the redundancy within the system to cope with N-1 events.

Overall, whilst these strategies reduce the estimated impact of such incidents, they do not completely mitigate the possibility of these types of incidents.

9.3 What is the cost of such incidents to GasNet?

As explained earlier, bomb threats and extortion can have significant economic impacts on the business. Our methodology for calculating the self insurance risk premium for GasNet's Gas Transmission system for these risks is outlined below.

9.3.1 Bomb Threat to the Gas Transmission Business

The information for the analysis of bomb threat and extortion risks was derived from three main sources: GasNet, The Australian Bomb and Data Centre (ABDC) and other Gas providers.

According to GasNet, there has not been a bomb threat, hoax or extortion event for the past 12 years since they were established in 1995.[15]

We have obtained bomb threat incident and statistic reports spanning 7 years from 1999 - 2005[16] from ABDC. A summary of the results is shown in Table 9-1:

[15] Information from GasNet Staff – Bruce Rose (Manager, Assets and Technical Regulations)
[16] Source: http://www.afp.gov.au/__data/assets/pdf_file/33600/Australian_Bomb_Data_Centre_Annual_Report_2005.pdf

Table 9-1 – Analysis of ABDC Reported Incidents

	Australia Federal Police (AFP) Australian Bomb Data Centre (ABDC) 1999 - 2005 Incidents Reported																				
	2005			2004			2003			2002			2001			2000			1999		
	AUS	VIC	% V	AUS	VIC	% V	AUS	VIC	% V	AUS	VIC	% V	AUS	VIC	% V	AUS	VIC	% V	AUS	VIC	% V
B	183	6	3.3	197	4	2.0	242	1	0.4	278	4	1.4	415	13	3.1	222	23	10.4	237	28	11.8
AB	25	1	4.0	37	2	5.4	37	2	5.4	38	3	7.9	37	2	5.4	39	7	17.9	38	1	2.6
H	16	6	37.5	21	2	9.5	15	1	6.7	32	6	18.8	29	0	0.0	27	4	14.8	24	2	8.3
R	61	1	1.6	122	9	7.4	137	3	2.2	161	1	0.6	121	4	3.3	66	14	21.2	17	2	11.8
T	5	0	0.0	1	0	0.0	12	0	0.0	5	0	0.0	6	0	0.0	19	2	10.5	6	0	0.0
B + AB + H	224	13	5.8	255	8	3.1	294	4	1.4	348	13	3.7	481	15	3.1	288	34	11.8	299	31	10.4

Total counts of B + AB + H for AUSTRALIA from 1999 - 2005	2189	
Total counts of B + AB + H for VICTORIA from 1999 - 2005	118	
Percentage (%) of B + AB + H for VICTORIA from 1999 -2005 Compare to AUSTRALIA	5.39	
Counts of B + AB + H targeting AUSTRALIA Utility from 1999 - 2005	6	
Counts of B + AB + H targeting VICTORIA Utility from 1999 - 2005 (5.39%)	0.323	
Likelihood of Bomb Threats (B + AB + H) targeting VICTORIA Utility	1 in	30.92 years

Classifications of Reported Incidents

(B) = Bombing - An incident where an Improvised Explosive Device (IED) has functioned as designed.

(AB) = Attempted Bombing - An incident where there has been an attempt to function an IED. The item has subsequently failed to function as a result of design or construction flaws, or as a result of reactive measures undertaken by response personnel.

(H) = Hoax - An item that is placed, designed or manufactured in a manner that is intended to cause an other person to believe that it is an IED

(R) = Recovery - Location of explosive components or other IED components that have been identified as stolen.

(T) = Theft - The theft of explosives and associated materials.

Investigating the 1999 – 2005 data obtained from the ABDC, 6 counts of bomb threats, which include bombings, attempted bombings and hoaxes, targeted Australia's utility companies. Since Victoria accounts for 5.39% of bomb threats, this equates to 0.323 count (less than 1) for the same 7 years period, or approximately one bomb threat targeting Victoria's utility companies every 31 years[17]. This incident rate would include all Victorian utilities and not just GasNet. However, given that GasNet is one of the main utilities in Victoria with assets in most populated areas of the stated, we have adopted the 1:31 years incident rate.

Furthermore, we understand that a gas distributor has recently experienced the effects of a bomb hoax, but as they were not the target of the bomb threat, this has not been included as an incident for utilities. This highlights the fact that the target of the bomb threat, hoax or bomb attempt does not need to be a utility to have an impact on the utility, as if the threat is in the vicinity of GasNet's assets, it may impact upon its business.

[17] ABDC only provides Australia wide data for specific targets and did not specify counts for Victoria bomb threats targeting utility.

However, for the purposes of this analysis, only incidents where utilities have been the targets are used to determine the probability. Therefore, Saha International has assumed a 1 in 31 year's occurrence for a bomb threat event, consistent with the stats from the ABDC, which results in an annual probability of 3.23%.

As mentioned earlier, a gas distributor had recently experienced a bomb hoax, where a car, which was thought to be laden with explosives, was parked close to a police station, in an area serviced by their network system. Although this bomb threat was a hoax and was not targeting their asset, there were still significant contingency costs associated with the deployment of emergency management team and standby crews. The estimated cost was approximately $5,200[18] per day, with the additional cost having to be incurred for 2.5 days (60 hours). Saha International has assumed that this $13,000 is a representative cost associated with an attempted bombing or bomb hoax.

Furthermore, GasNet has estimated that a bomb threat at their Dandenong site would cost an additional $17,000 per day[19] or $42,500 for 2.5 days. This calculation is based on a loss of productivity of about 50 employees, assuming a median remuneration of $75,000 per annum inclusive of superannuation.

We have assumed bomb threat related costs to be $42,500 under the assumption that the bomb threat would more likely to be directed at the main Dandenong site.

Over and above this, there is a real risk that the detonation of a bomb may impact upon GasNet's ability to deliver gas, and also, on the structural integrity of its gas transmission network. The costs (both direct and indirect) would be significantly higher than just a threat, due to, for example, the need to shut down an area of the network system, mobilise significantly more crews to be on stand-by, the need to purge the system, revenue losses, the potential compensation claims, and the cost of fixing the affected asset. With reference to GasNet Insurance Manual, this is a legitimate and potentially costly risk that GasNet is currently self insuring. However, it is very difficult to quantify the risk of a bomb being detonated, due to the lack of data. There are numerous factors that would need to be considered to adequately support an 'impact' figure, for example, location, life lost, third party damage and associated costs due to subsequent business interruptions to GasNet and their customers.

We also note that it is equally difficult to distinguish whether the bombing by a 'disgruntled' employee can be categorised under a terrorism event, which is subject to a cost pass through provision, or not. This is because a bomb threat by anybody can be interpreted to be an act of violence by an individual's ideology to put the public in fear. Therefore, we recommend that the definition of terrorism be further refined to incorporate this risk, and in the event that a non-terrorist related bombing does eventuate, the cost associated be passed through under a specific cost through mechanism pertaining to the non-terrorist related impact of a bomb threat or extortion.

[18] Information obtained from a gas distributor.

[19] We assume a 44 weeks work year (after the exclusion of annual & sick leave + public holidays)
75,000 ÷ 44 ÷ 5 = $340 per day (assuming a 5 days work week)
$340 * 50 = $17,000 per day for 50 employees averaging $75,000 pa salary

9.4 Total Self Insurance Risk Premium

Therefore, Saha International believes that in addition to the adoption of a specific cost pass through provision for non-terrorist related bomb events, GasNet be allowed to include the following self insurance risk premium for the risk of a bomb threat / bomb hoax / extortion occurring in its operating and maintenance expenditure forecasts.

The Self Insurance Risk Estimate = Probability of Bomb Threats * Costs Due to the Threats

= 0.032 * $42,500

= $1,360 per annum

The risk premium estimate is $1,400 pa.

10. KEY PERSON RISK

10.1 Introduction

GasNet's continued success is dependent on its ability to recruit, train, motivate and ultimately retain highly skilled employees. Competition for senior officers and engineers needed to perform the essential functions of GasNet's business is currently extremely high in Australia, especially in the energy and infrastructure based industries.

Given a limited supply of skilled transmission employees, an inability to retain key employees could lead to increased labour costs. Even when it is possible to replace key people, it often takes a considerable period of training before they possess the same level of skills required to work effectively with the complex and sometimes dangerous facilities used in GasNet's business. Therefore, in addition to increased labour costs, there could be disruption of services and even financial losses.

10.2 Description of Risk

Key person risk represents the risk that GasNet could incur costs that are over and above their base O&M forecasts, due to the sudden departure, or death, of key employees. A key employee is an employee who has a specialised and/or unique skill, or specific level of expertise or experience, that is integral to the ongoing success of GasNet's core business. This can be any employee throughout the business, ranging from managers, engineers, senior management and other senior officers (amongst others).

Typically, GasNet would find it difficult to replace a key employee in the short-term, with the process of replacing a key employee likely to require a more intense recruitment process (i.e. if the skills, expertise and experience are not available locally and need to be sourced from overseas or interstate), which in turn incurs greater expense than would otherwise be the case for other non-key employees.

10.3 Current Insurance Provisions

Generally, key person insurance is available to a business to cover against business interruptions and costs arising from the sudden departure or death of a key employee. However, GasNet has not retained any external insurance arrangements, choosing instead to self-insure for exposure to key person risk.

10.4 Quantification of Self-Insurance Risk Premium for Key Person Risk

The calculation of a self-insurance risk premium associated with each identified key employee is based on the simple formula shown below:

Key Person Risk Premium = *{Financial Exposure x Probability of Leaving Service}*

10.5 Identification of Key Persons

GasNet has identified 24 key operational people in their organisation, each of which posses specialised industry, discipline or company specific knowledge, and experience that cannot be easily replaced. The departure or death of one of these employees would adversely affect the financial position of the company due to the following reasons:

- Their replacement in the short-term is not likely due to the level of expertise or experience required;

- Their replacement may have to be from overseas or interstate due to the limited availability of specialised expertise locally;

- It is expected that considerable additional expenses would be incurred in respect of recruitment, relocation and settlement costs; and

- Loss of income would follow from the disruption to the company's core business and the time required for the replacement to understand the company's processes and strategies.

Table 10-1 - Summary of GasNet Key Operational Personnel

TYPE OF POSITION	Number of People	Average Age
Manager	13	50.15
Lead Engineer	2	47.50
Other Senior Officers	9	51.00
Total Key People	24	50.25

In addition to the operational key people, GasNet has identified two senior executives with deep understanding of GasNet's business.

10.6 Exposure to Key Person Risk

GasNet has provided Saha International with their quantification of the expected adverse financial impact arising from the sudden departure or death of their key persons. The adverse financial impact for each key person consists of two components: recruitment costs and business disruption costs.

According to GasNet, recruitment is currently particularly difficult for experienced (i.e. more than 8-10 years relevant experience) engineers and dual trade electrical/instrumentation technicians. For example, GasNet recently filled a Principal Mechanical Engineer position after a waiting period of over two months. Meanwhile, the post of Principal Electrical Engineer had been vacant for about 6 months as at end March 2007. According to GasNet the difficulty in recruiting for these types of positions may result in higher than anticipated starting salaries to be competitive, as well as increased advertising costs for multiple advertisements. The methodology used by GasNet, to estimate both cost components, has been outlined in Table 10-2 below.

Table 10-2 - GasNet's quantification of their key person risk exposure

	Description	Quantification used by GasNet
Component 1: **Recruitment Cost**	This is an estimate of the cost of recruiting key persons and consists of recruitment consultant costs and newspaper advertising costs.	Consultant costs per position = total remuneration (i.e. base salary, super and vehicle) * Consultants' fee %. GasNet has used their typical consultants' fee percentage of 10%-18% of total remuneration depending on the type of position. Advertising costs consist of newspaper advertising costs (Internet advertising costs are often included in consultant's fees). GasNet has used newspaper advertising costs in the range of $3,000 to $4,500 to estimate their recruitment costs. For some positions, advertising cost is double as there is a need to advertise locally and interstate.
Component 2: **Business Disruption Cost**	This is an estimate of the specific costs related to any loss/reduction of business income in the initial period of employment when the new recruit is not fully operational. This includes issues related to the speed at which a new recruit acquires specific knowledge.	Annual business disruption cost per key person = Annual salary of key person * (number of months disruptions are expected to occur/12) * disruption discount factor. The disruption discount factor is the % of the annual salary that is estimated to be lost as a result of business disruptions. GasNet has used a disruption discount factor of 30%.

The recruitment and business disruption costs for the senior executives are consistent with the average costs assumptions used at the last regulatory reset (which were based on estimates after discussions with GasNet).

Using this methodology, the financial exposure of key person risk is calculated as follows:

Financial Exposure = *{Recruitment Cost + Business Disruption Cost}*

Based on the quantification above, Table 10-3 shows our estimate of GasNet's exposure to key person risk.

Table 10-3 - Estimated Financial Exposure to Key Person Risk

TYPE OF POSITION	Average Salary	Average Recruitment Costs	Average Business Disruption Costs	Number of People	Estimated Financial Exposure
Manager	$ 120,377	$ 26,796	$ 37,230	13	$ 832,336
Lead Engineer	$ 95,368	$ 21,311	$ 21,473	2	$ 85,569
Other Senior Officers	$ 72,282	$ 10,703	$ 14,837	9	$ 229,856
Total Key Operational People	$ 100,257	$ 20,304	$ 27,520	24	$ 1,147,761
Total Key Senior Executive		$ 50,000	$ 375,000	2	$ 850,000

10.7 Probability of a Key Person Leaving GasNet

The probability of a key person leaving the service of GasNet can be calculated based on a combination of information relating to probabilistic rates of resignation, mortality and disablement. These rates are dependent on and vary with the age of each person.

We have derived the average probability of each GasNet Manager, Lead Engineer and Senior Officer leaving the service of GasNet using resignation, mortality and disablement factors referenced in an Actuarial Review of the Victorian Energy Industry Superannuation Fund (prepared by William M Mercer). These are shown in Table 10-4 below. There is a risk of key personnel being poached by other utilities. This risk is a reality for all the major utilities as there are shortages of resources in key areas. Due to the difficulty in determining the rate of poaching amongst the utilities, the probability used for this risk analysis is conservatively based on the resignation, mortality and disablement factors mentioned above.

Table 10-4 - Key Person Risk - Probability of Leaving Service

TYPE OF POSITION	Average Age	Probability of Leaving Service
Manager / Senior Exec	50	1.88%
Lead Engineer	48	1.62%
Other Senior Officers	51	1.98%
Total Key People	50	1.90%

10.8 Estimated Self-Insurance Premium - Key Person Risk

Based on the above information, we estimate the total self-insurance premium for GasNet's key person risk to have a value of $37,500 pa. The detailed results are shown in Table 10-5.

Table 10-5 - Estimated GasNet Financial Exposure to Key Person Risk

TYPE OF POSITION	Estimated Financial Exposure	Estimated Total Risk Premium
Manager	$ 832,336	$ 15,460
Lead Engineer	$ 85,569	$ 1,398
Other Senior Officers	$ 229,856	$ 4,620
Senior Exec	$ 850,000	$ 15,980
Total: Annual	$ 1,997,761	$ 37,457

APPENDIX 1: TABLE OF FOOTNOTE REFERENCES

1. http://www.ausstats.abs.gov.au/ausstats/subscriber.nsf/0/EBCBD69C6D392239CA2568EA007D9B76/$File/63220_1999.pdf
   http://www.abs.gov.au/Ausstats/abs@.nsf/39433889d406eeb9ca2570610019e9a5/3b174c96a82857e4ca256eb5007b5722!OpenDocument
   http://www.abs.gov.au/Ausstats/abs@.nsf/Previousproducts/5692B0C63E16F30ECA2570DE0007B492?opendocument
   http://www.ausstats.abs.gov.au/ausstats/subscriber.nsf/0/CA25687100069892CA25688900257843/$File/63210_Mar%201998.pdf
   http://www.abs.gov.au/Ausstats/abs@.nsf/7d12b0f6763c78caca257061001cc588/FDE57E5652E0A63FCA2572360002043D?opendocument
2. (103 / 1000) * 9.375 = 0.966 days
3. We assume a 44 week work year (after exclusion of annual leave, sick leave and public holidays)
   75,000 / 44 / 5 = $340 per day (assuming a 5 day work week)
4. ($13,000 * 3 + $25,000) / 4 = $16,000
5. http://www.abanet.org/poladv/priorities/asbestos.html
6. The Economist - The war on tort, 26 Jan. 2005
7. ABC News Online, Updated Thursday February 15 2007
8. Information from GasNet Staff – Bruce rose (Manager, Assets and Technical Regulations)
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10. http://www.ir.jameshardie.com.au/jh/asbestos_compensation.jsp#KPMG
11. Sourced from Email from Paul Callander dated 05/04/2007 Subject - GasNet Pipeline Data
12. Sourced from Insurance Manual 2005-2006 GasNet Australia Limited, 18 January 2006, Marsh
13. KPMG Fraud Survey 2006
14. KPMG Fraud Survey 2006
15. KPMG Fraud Survey 2006, 2004.
16. The results are based on 196 organisations providing details of an individual fraud. They are summarised by type in the table, showing also the average value attributable to each fraud type.
17. Two hundred and six usable questionnaires identifying an individual fraud for more detailed study were used. They are summarised by type in the above table showing the average loss attributable to each fraud type.
18. Default Study: Australia & New Zealand 2005 Annual Default & Rating Transitions, Standard and Poor's, September 2006
19. Australian Macroeconomic Performance and Policies in the 1990s: http://www.rba.gov.au/PublicationsAndResearch/Conferences/2000/GruenStevens.pdf
20. Email from Paul Callander sent on 23rd March 2007.
21. Email from Paul Callander sent on 28th March 2007.
22. Email from Paul Callander sent on 28th March 2007.
23. GasNet Australia Access Arrangement, Commencement date: 1 January 2005.
24. Email from Paul Callander sent on 23rd March 2007.
25. Email from Paul Callander sent on 28th March 2007.
26. Websites for the credit rating agencies are:

- S&P (AUS & NZ):
http://www2.standardandpoors.com/portal/site/sp/en/au/page.topic/ratings_corp/2,1,3,0,0,0,0,0,0,0,4,0,0,0,0,0.html
- S&P (EU):
http://www2.standardandpoors.com/portal/site/sp/en/eu/page.topic/ratings_corp/2,1,3,0,0,0,0,0,0,0,4,0,28,0,0,0.html
- Fitch (AU):
http://www.fitchratings.com.au/corporateslist.asp

Note: Country Energy is owned by the New South Wales (NSW) government. While Country Energy is not guaranteed by the NSW economy, the potential political repercussions were it not to be supported and the fact that it still operates in an environment created and partly managed by the NSW government. We have also assigned Energy Australia the same credit risk to Country Energy given that both companies have similar ties to the NSW government. Note that the Credit Rating applied to Visy was sourced from their published document, 'The Visy Report, National Packaging Covenant' and their website (http://www.visyflow.com.au/infoModule/otherSites%5Cvisy.asp).

27. Default Study: Australia & New Zealand 2005 Annual Default & Rating Transitions, Standard and Poor's, September 2006.
28. For the purposes of assigning default probabilities to the credit ratings from Table 1, the '+' and '-' signs attached to the ratings have been dropped.
29. Email from Paul Callander sent on 28th March 2007.
30. The 56 days of exposure was derived from the sample GTD contract by taking the sum of:
    - The 30 day lag associated with invoicing for the preceding month (Section 3.3(a))
    - The 18 business days lag for the issuing of the invoice to the Shipper (Section 3.3(a))
    - The allowance of 8 business days for a Shipper to pay the invoice (Section 3.3(c))
31. Email from Paul Callander sent on the 23rd of March 2007 stated that the recovery from a Pass Through Provision is likely to be about 2 years after the event.
32. This insured amount is approximately 1 month's worth of the regulated revenue generated through the GTDs, which is $9.453 million.
33. Approved by ACCC on 15 Dec 2004 and commencement date on 1 January 2005
34. Insurance Manual 2006 – 2007 GasNet Australia Limited by MARSH
35. Powerlink Queensland Transmission Network Revenue Cap 2007-08 to 2011-12, pg 165 -167
36. Information from GasNet Staff – Bruce rose (Manager, Assets and Technical Regulations)
37. Source:
http://www.afp.gov.au/__data/assets/pdf_file/33600/Australian_Bomb_Data_Centre_Annual_Report_2005.pdf
38. Information obtained from another TNSP

GasNet Access Arrangement Submission (Schedules & Attachments)

Attachment F - Synergies WACC report

Weighted Average Cost of Capital Review for GasNet Australia

April 2007

Synergies Economic Consulting Pty Ltd
www.synergies.com.au

Disclaimer

Synergies Economic Consulting (Synergies) has prepared this advice exclusively for the use of the party or parties specified in the report (the client) and for the purposes specified in the report. The report is supplied in good faith and reflects the knowledge, expertise and experience of the consultants involved. Synergies accepts no responsibility whatsoever for any loss suffered by any person taking action or refraining from taking action as a result of reliance on the report, other than the client.

In conducting the analysis in the report Synergies has used information available at the date of publication, noting that the intention of this work is to provide material relevant to the development of policy rather than definitive guidance as to the appropriate level of pricing to be specified for particular circumstance.

Contents

Executive Summary

GasNet Australia (GasNet) is responsible for the ownership and maintenance of Victoria's high pressure gas transmission network. GasNet has engaged Synergies Economic Consulting (Synergies) to review its Weighted Average Cost of Capital (WACC) as part of its forthcoming regulatory review by the Australian Energy Regulator (AER).

Gas competes with a number of energy sources. Its relative competitiveness depends on the competitiveness of its key sectoral components, including the upstream supply of gas, the gas transportation sector and downstream wholesale and retail markets. Since 2000-2001 natural gas has accounted for approximately 18% of Victoria's primary energy consumption, which represents a decline from a peak of 22% in the mid-1990s. Brown coal and petroleum remain the dominant sources of primary energy. At least from the perspective of residential demand, electricity has been (and is expected to remain) the dominant energy source, with gas regarded as a 'fuel of choice'.

Methodology

The WACC has been estimated using the nominal post-tax 'vanilla' formulation. The cost of equity has been determined using the domestic CAPM, which remains the most commonly used asset pricing methodology notwithstanding its recognised shortcomings.

WACC estimation is inherently imprecise, and hence the probability of estimating a WACC that is different from the 'true' WACC is high. In this regard, it is important to consider the asymmetric consequences of regulatory error. It is generally recognised that if prices are set too low, the resulting under-investment is worse from an economic and social perspective than the impact of monopoly profits resulting from prices that are set too high. Given this, the estimation of the regulated WACC should seek to lower the probability that the true WACC is higher than the estimate (that is, lower the chance that the WACC is underestimated).

Parameters

Our estimates for each parameter (which in some cases is a range), and the calculated WACCs, are provided in the table at the end of this Executive Summary. A brief discussion of our views on each of the key parameters follows.

Risk-free rate

We have calculated the average ten-year Commonwealth Government bond rate over a forty day period ending on the 26 February 2007. The rate estimated was 5.85%.

Capital structure

An assumption of 60% debt to total value has been consistently applied in energy regulatory decisions and is the recommended value under the AER's Statement of Regulatory Principles. Although this is higher than the historical five year average capital structure maintained by domestic and overseas gas distribution firms that we have examined, we are of the view that a value of 60% is not unreasonable.

Beta

We have used three approaches to estimate beta.

First, we estimated a beta for GasNet (which has since been delisted) by regressing its returns over the past five years against the returns on the ASX200. However, the fact that GasNet shares were infrequently traded poses significant issues for estimation. We therefore do not believe that the estimate can be in any way relied upon.

Second, we undertook a first principles analysis. This qualitative assessment examines the key drivers of systematic risk and provides important context for the interpretation of beta estimates, including data from comparable companies. This analysis concluded that GasNet is considerably exposed to systematic volume risk.

Third, we have examined a sample of comparable companies from a sample of firms that operate in the gas industry (after discarding firms whose business profile was seen as being too dissimilar to GasNet's, or their beta estimate was of statistically poor quality). The average asset beta of eleven US firms was 0.46, and the average asset beta for the total sample of twenty-nine gas distribution firms (including the US firms) was 0.54.[1]

As part of the comparable companies analysis, we also examined regulatory precedent. An equity beta of 1 has consistently been adopted in Australian energy regulatory

1 These estimates are Blume adjusted. The averages of the raw beta estimates were 0.49 (US firms) and 0.5 (all firms).

decisions (under different forms of regulation) and is the recommended parameter value in the AER's *Statement of Regulatory Principles* for electricity transmission.

There is no evidence to suggest that GasNet's equity beta should be less than 1, which assuming a capital structure of 60% is equivalent to an asset beta of 0.4. We are of the view that gas does have a higher risk profile than electricity, although the only regulator to have drawn this distinction to date is the QCA.

While caution should be exercised in drawing inferences from other jurisdictions, the data from our global sample would suggest that the true value of the equity beta may be higher than 1. We are therefore firmly of the view that there is no basis to go below an equity beta of 1 and to do so would significantly increase the probability that the estimated WACC is lower than the true WACC (that is, increase the risk of regulatory error).

We have concluded that a reasonable range for GasNet's equity beta is between 1 and 1.2 (which equates to an asset beta range of between 0.4 and 0.49 based on a capital structure of 60%). The lower bound has been set with reference to regulatory precedent, and the upper bound is based on the evidence from the comparable companies analysis.

Market risk premium

There is considerable uncertainty surrounding the estimation of the market risk premium (MRP). In the short-term, the MRP is volatile and caution should therefore be exercised in attributing trends based on estimates produced over short horizons.

The long-term average estimate of approximately 7% for the MRP significantly exceeds the regulatory precedent of 6%. While there is some debate surrounding the possibility that the value of the MRP has fallen, there is no empirical evidence to quantify this. Hence, until there is sufficient empirical evidence to quantify the potential impact of structural change on the MRP, long-term historical estimates remain the most appropriate benchmark.

The assumption of 6% adopted by regulators should therefore still be regarded as the lower bound of a reasonable range, which we believe to be between 6% and 7%.

Cost of debt

We believe a notional credit rating assumption of BBB is appropriate for GasNet. We have therefore estimated a margin based on the difference between the forty day average of the Commonwealth Government bond rate and the BBB bond rate, for the period ending 26 February 2007. Before debt-raising costs, the estimated debt margin was 114 basis points, resulting in a cost of debt of 6.99%.

Gamma

Recent robust empirical investigations have concluded that the value of franking credits is zero since the introduction of the 45-day rule (Bellamy and Gray, 2004; Cannavan, Finn and Gray, 2004). This is predicated on the key assumption that the marginal investor is foreign, which is considered appropriate given the presence of foreign investors in the Australian market. We are of the view that it is appropriate to recognise the presence of foreign investors in the Australian market while retaining a domestic CAPM. This is because:

- an international CAPM is difficult to specify, and assumes that capital markets are fully integrated, which is not the case; and
- re-specification of the domestic CAPM to exclude foreign investors is not only extremely difficult to do but ignores the practical influence that these investors do exert in the Australian market (reflecting the partial, but not full, integration of global capital markets).

Additionally, we conducted a basic but informative test of the market's behaviour with regards to the ex-date price response, which finds that for fully-franked and unfranked dividends, the market responded equally to the cash dividend only, which is further evidence of the worthlessness of franking credits. As an extension to this model, we tested whether or not franking credits were valued by the market at 50%, 70% or 100% of their face value. We emphatically rejected each of the three alternative values. All in all, there is insufficient evidence to reject the theoretical hypothesis that franking credits are worthless.

On the basis of the evidence we believe that it is appropriate to assume a value of zero for gamma. This evidence includes:

- evident difficulties in estimating a reliable value for gamma (which may be because it has no value);
- a strong theoretical foundation, being that since the introduction of the 45-day rule, franking credits are now of no value to the marginal foreign investor (whereas they may have had some value prior to this); and
- empirical evidence to support a value of zero, both from the recent literature and our own analysis which confirmed that we cannot conclude that gamma has a value other than zero.

We have therefore adopted a value of zero. We are of the view that there is now sufficient evidence emerging to prompt a review of this precedent by regulators and a revision of the point estimate.

Inflation

We have derived a current estimate for inflation implied by the ten year Commonwealth Government nominal and indexed bond yields, applying the Fisher equation (based on the same period ending on the 26th of February 2007). We have used this approach as it is commonly used in regulatory practice and is consistent with the methods used to estimate the risk-free rate and debt margin. The resulting estimate for inflation is 3.09%.

WACC

The resulting WACC estimate is provided in the following table.

GasNet: WACC Estimate

Parameter	Synergies' Recommended Range
Nominal risk-free rate[a]	5.85%
Debt proportion	60%
Equity proportion	40%
Debt margin[b]	1.14%
Market risk premium	6% - 7%
Gamma	0
Debt beta	0
Equity beta	1-1.2
Asset beta[c]	0.4-0.49
Tax rate	30%
Inflation	3.09%
Cost of debt	**6.99%**
Cost of equity	**11.85% - 14.25%**
NOMINAL POST-TAX WACC	**8.93% - 9.89%**

a Based on a 40 day average for the period ending 26 February 2007.

b Based on a 40 day average for the period ending 26 February 2007, assuming a notional credit rating of BBB. **Does not include allowance for debt-raising costs.**

c Based on the Monkhouse formula.

1 Introduction

GasNet Australia (GasNet) owns and maintains a 1,931 kilometre high pressure gas transmission pipeline network which services residential, commercial and industrial customers in Victoria. GasNet's role is to provide:

- high pressure transmission pipelines and associated assets;
- ongoing maintenance services to maintain the reliability and safety of these pipelines and associated assets; and
- connection and other services to gas suppliers, distributors and directly connected customers.

This network is covered under the *National Third Party Access Code for Natural Gas Pipeline Systems* (the Code), with responsibility for regulation having recently been assumed by the Australian Energy Regulator (AER).

Synergies Economic Consulting (Synergies) has been engaged by GasNet to review its Weighted Average Cost of Capital (WACC) for the purpose of its forthcoming regulatory review. The report is structured as follows:

- section 2 provides an overview of GasNet's business and the industry it operates in;
- section 3 outlines the methodology that has been used to estimate WACC, and identifies some of the key issues surrounding WACC estimation, including the inherent uncertainty of the process and the asymmetric consequences of regulatory error;
- section 4 details the approach used to estimate values for each parameter; and
- section 5 summarises the estimates.

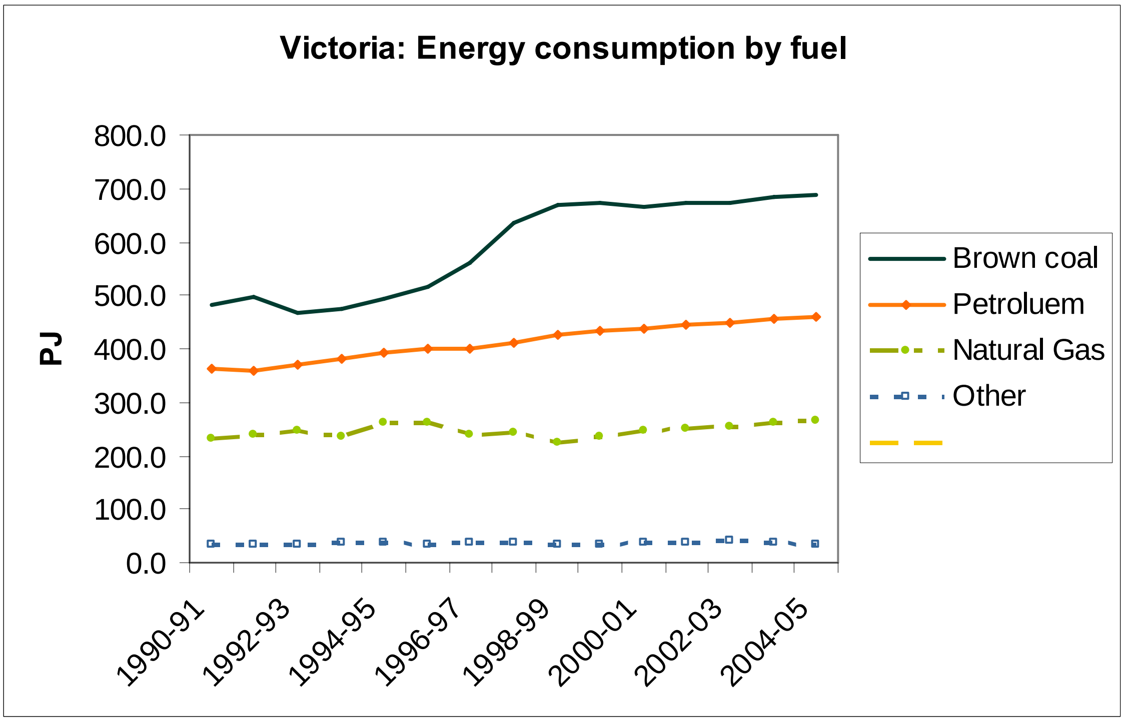
2 GasNet's Business

2.1 The gas industry

The gas sector and its relative competitiveness is driven by the efficiency and competitiveness of the underlying sector components, namely, the upstream supply of gas, the gas transportation sector and the downstream wholesale and retail markets..[2] Since 2000-2001 natural gas has accounted for approximately 18% of Victoria's primary energy consumption. This represents a material decrease from 1994/95 when the share of primary energy accounted for by natural gas peaked at some 22%. Gas's current share of primary energy is roughly in line with its share of overall energy consumption in Australia, which was around 19%, although this share has been increasing, rather than decreasing (from around 17% in the early 1990s). Figure 1 shows Victoria's primary energy consumption by fuel since 1990-91.

2 ABARE (2003), Australian Gas Markets: Moving Towards Maturity, Commonwealth of Australia, Canberra.

Figure 1 Victoria: energy consumption by fuel



Note: Excludes derived fuels (coke, town gas and thermal electricity).
Data source: ABARE (2006), Energy Consumption by Fuel.

This shows that the consumption of gas has increased relatively slowly (1% per year), compared to Victoria's major energy source, brown coal (2.5% per year) and petroleum (1.8% per year). As consumption has been growing over this period, this means that the relative share of gas has declined.

With respect to the outlook for the demand for energy, ABARE notes that this will mainly be driven by economic growth.[3] It expects primary energy consumption in Australia to increase by an average rate of 1.9% per annum to 2029-30, compared to projected GDP growth of around 3% per annum in the long-term. This growth will be more subdued in Victoria compared to some of the other states.

Australia's projected growth is expected to largely be driven by the expansion of energy-intensive refining and minerals processing. Overall, the energy intensity of industry has declined, falling by an average of 1.1% per annum during the 1990s.[4] However, consumption of energy per person is expected to rise.

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[3] ABARE (2005), Australian Energy: National and State Projections to 2029-30, Commonwealth of Australia, Canberra.

[4] ibid., p.2. Based on total primary energy consumption per dollar of GDP.

Petroleum products are expected to continue to dominate growth, contributing nearly 50% of the total increase in primary energy consumption, with natural gas expected to account for 24% (which is closely linked to developments in the nonferrous metals and chemicals sectors).[5]

In the residential sector, electricity currently accounts for around 49% of consumption, and gas 31%. By the end of 2029/30, these relative shares are expected to remain reasonably constant at 51% and 31% respectively (with both increasing their market share slightly, mainly at the expense of wood).[6] The commercial sector is more dependent on electricity.

In 2004-05, the rate of increase in energy production was 7.5%, which significantly exceeded the rate of increase in energy consumption (around 1.9%).[7] Production of coal, which accounts for approximately half of total energy production, increased by approximately 6%. Production of natural gas and uranium increased by 10% and 15% respectively.

2.2 Overview of GasNet

GasNet is responsible for the ownership and maintenance of Victoria's high pressure gas transmission pipeline network. VENCorp is responsible for the operation of the network. GasNet and VENCorp have entered into a Service Envelope Agreement, which defines the level of capacity to be provided by GasNet under its access agreement.

In addition to owning and maintaining the Victorian assets, GasNet operates and maintains the 443 kilometre Telfer pipeline in Western Australia, which had its first full year of operation in 2005. The revenue from this pipeline, which is not covered under the Code, is underpinned by fixed price take-or-pay contracts. This contrasts with the situation in the Victorian market, which operates on a market carriage basis (this is discussed further below). Other activities include:

- the operation of a 12,000 tonne LNG tank and the provision of metering and connection services; and
- the provision of specialist engineering and project management services.

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5 ibid., p.4.

6 ibid.

7 ABARE (2006), http://www.abareconomics.com/interactive/energy/index.html.

Table 1 shows the composition of GasNet's revenue for the year ended 31 December 2005:

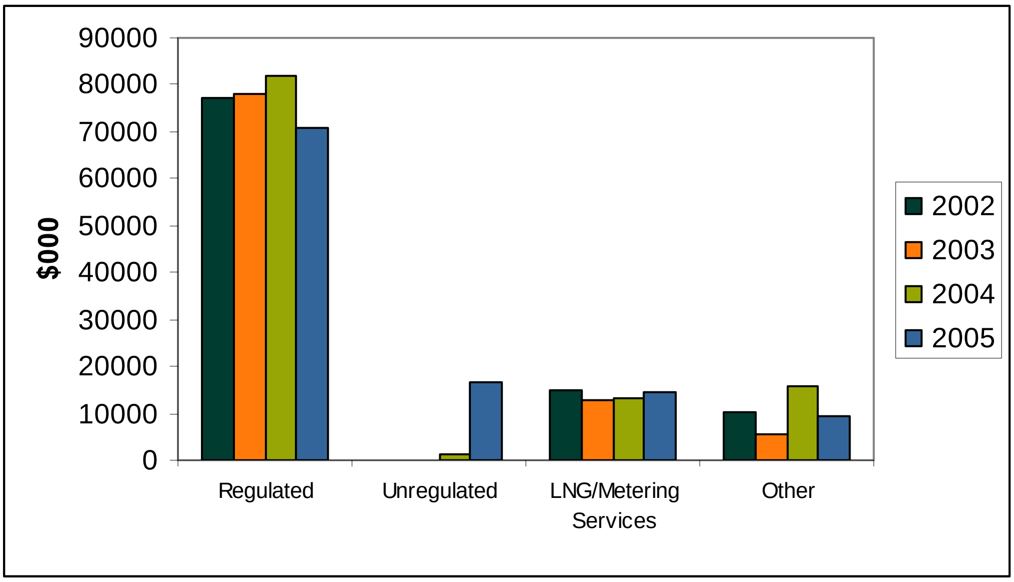
Table 1 GasNet: Composition of revenue (year ended 31 December 2005)

Source	Revenue $000	% of total
Regulated transmission revenue	70,664	63.5%
Unregulated transmission revenue	16,567	14.9%
LNG/metering services revenue	14,584	13.1%
Other	9,403	8. 5%
Total	111,218	

Source: GasNet Australia (2005), Infrastructure for Generations: GasNet Australia Group Annual Report 2005, p.42.

Regulated transmission revenue was down 13.7% from the previous year due to unseasonally warm weather in Victoria. Revenue composition for the last four years is shown in Figure 2.

Figure 2 GasNet: regulated revenue (year ended 31 December)



Data source: GasNet, Annual Reports.

2.3 Regulated business

The regulated transmission business is the focus of this review. The Victorian market consists of approximately 1.4 million residential customers and 43,000 industrial and commercial users. In revenue terms, small customers include both residential and commercial customers and account for approximately 55% of revenues (this class of customers consume less than 10,000GJ per annum and are subject to Tariff V). The balance is represented by large industrial and commercial customers (Tariff D).

Participants intending to ship gas through the network must register with VENCorp, however will enter into a connection agreement directly with GasNet. TUOS charges will therefore be directly payable to GasNet (charges are also payable to VENCorp). Transmission charges are based on GasNet's published reference tariffs.

Overall, the demand side is reasonably concentrated. In 2003, ABARE observed that:[8]

> Approximately five firms in Australia account for nearly 25% of all domestic gas consumption and a further 25-35 firms account for an additional 25% of consumption.

This may change as the market evolves and jurisdictions progress towards full retail contestability. At the same time, industry consolidation may also occur.

As noted above, the Victorian market operates on a market carriage basis, which is partly driven by the interconnected nature of the transmission network (compared to point to point, which is typical in other states). This means that there are no contractual arrangements committing users to certain volumes and charges are levied on a usage basis. This contrasts with a contract carriage structure where users contract for volumes. These contracts often include take-or-pay provisions which provide considerably increased certainty to the network owner.

8 ABARE (2003), op.cit., p.8.

3 Methodology

3.1 Regulatory guidelines

The AER's *Statement of Regulatory Principles*[9] (the AER's Principles) provides guidelines with respect to estimation of WACC. While the guidelines only apply to the regulation of electricity transmission, reference is likely to be made to these principles when making decisions in relation to gas transmission. The AER's Principles prescribe that:

- the WACC formulation is the post-tax nominal (vanilla) approach;
- the cost of equity will be based on CAPM;
- the risk-free rate will be based on the ten-year Commonwealth Government bond, calculated using a moving average for a period of between five and forty days (to be selected by the TNSP);
- the following parameter values will apply:
  - a value of 6% for the market risk premium;
  - an equity beta of one;
  - a benchmark credit rating of A for the purpose of determining the debt margin;
  - gearing of 60% (debt to total assets); and
  - an average gamma of 0.5.

The Code provides that the rate of return:

> …should provide a return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the Reference Service…[10]

and

> …should be calculated by reference to a financing structure that reflects standard industry structures for a going concern and best practice…[11]

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9 Australian Energy Regulator (2005), Compendium of Electricity Transmission Regulatory Guidelines.

10 National Third Party Access Code for Natural Gas Pipeline Systems, November 1997, para. 8.30.

11 ibid., para 8.31.

However other approaches may be adopted if the regulator is satisfied that this is consistent with the objectives of the reference tariff principles. These objectives include:[12]

(a) providing the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the Reference Service over the expected life of the assets used in delivering that Service;

(b) replicating the outcome of a competitive market;

(c) ensuring the safe and reliable operation of the Pipeline;

(d) not distorting investment decisions in Pipeline transportation systems or in upstream and downstream industries;

(e) efficiency in the level and structure of the Reference Tariff; and

(f) providing an incentive to the Service Provider to reduce costs and to develop the market for Reference and other Services.

The Australian Competition Tribunal has highlighted that in accordance with the principles of the Code, the role of the regulator is not to determine the rate of return in accordance with the Code. Instead, the task of the regulator is to:

> …determine whether the proposed AA [Access Undertaking] in its treatment of Rate of Return is consistent with the provisions of s 8.30 and s 8.31 and that the rate determined falls within the range of rates commensurate with the prevailing market conditions and the relevant risk.[13] [words in square brackets added]

3.2 WACC methodology

A firm's WACC recognises that its capital is provided by two sources, namely lenders and equity investors (that is owners or shareholders), and is equivalent to the weighted average cost of servicing the various classes of financial claims on the firm. Each source of capital or financial claim will involve different risks and hence different costs.

For the purposes of this analysis a nominal post-tax WACC has been estimated using the following equation, which is most commonly referred to as the vanilla WACC:[14]

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[12] ibid., para 8.1.

[13] Application by GasNet (Australia) Operations Pty Ltd [2003] AcompT 6, para 42.

[14] This formulation is often referred to as "WACC 3" – see Officer, R.(1994), "The Cost of Capital under an Imputation Tax System" in Accounting and Finance, vol. 34(1), pp 1- 18.

$$WACC = R_e \frac{E}{E+D} + R_d \frac{D}{E+D}$$

This is consistent with the approach commonly used by regulators and as noted above is the approach recommended by the AER. This formulation adjusts for inflation, taxation and dividend imputation in the cash flows, rather than the cost of capital.[15]

3.3 CAPM

The Capital Asset Pricing Model (CAPM) remains the most widely used approach to estimating the cost of equity in both regulatory and commercial applications. This is despite a number of significant deficiencies, which are largely based on limiting assumptions.[16] One of the main assumptions underpinning CAPM is that returns are normally distributed. Owners of regulated infrastructure are often faced with an asymmetric return profile (that is, limited upside with unlimited downside), particularly with respect to risks such as asset stranding. A rate of return determined in accordance with the CAPM will therefore not provide compensation for asymmetric risks such as asset stranding.

A number of alternative approaches have therefore been postulated. However, none of these approaches are currently viewed as a superior asset pricing model to the domestic CAPM. While other methodologies are not superior to the CAPM approach, they may be used to test the reasonableness of the estimates. For example the Dividend Discount Model or the P/E ratio may be used as a check for the cost of equity

3.3.1 International versus domestic versions of the CAPM

The CAPM is normally specified as a domestic version, which means that its key parameters (being the risk-free rate, beta and the market risk premium) are specified based on Australian market data. Some suggestions have been made that an international CAPM should be used, recognising the increasing integration of world capital markets and the presence (and hence influence) of foreign investors in the

15 For example, expected tax payable (and expected values of imputation credits) is captured in the modelling as a cash flow in each year of the analysis. In addition, the cash flows represent the nominal (rather than real) cash flows for each year of the analysis.

16 A key criticism is that it is a single period model that cannot be readily applied in a multi-period setting. Further, almost all of the assumptions on which it is based can be questioned. For example: (1) not all investors can borrow and lend at the risk-free rate; (2) short-selling of physical assets is generally not permitted (with the exception of derivative instruments); (3) many investors will consider the implications of taxes and transaction costs when making investment decisions; and (4) investors tend not to have homogeneous expectations regarding risk and return. On the contrary, much trading activity, and price volatility is driven by differences in expectations (and 'decision models' used by investors to form these expectations), particularly between buyers and sellers.

Australian market. It assumes that capital markets are fully integrated, with international capital flows unrestricted, and investors exhibiting no home country bias.[17]

A number of versions of the model have been developed and typically require specification of the key parameters in a global market context (for example, using a global share price index instead of the All Ordinaries index).[18] As noted by the Strategic Finance Group, this is not practical:[19]

> Clearly, re-estimating all WACC parameters as they would be in the absence of foreign investment is an impossible task and this approach must be rejected. That is, all WACC parameters should be estimated as they are, not as they would be if a particular theoretical assumption were to hold.

In practice, the international CAPM has not been widely used. This is for a number of reasons:

- there are a number of alternative models that have been specified, however there remains no consensus view on which one should be used;
- the model is relatively complex to apply and its parameters are difficult to estimate, particularly the exchange rate covariances; and
- there is no empirical evidence to suggest that it provides a better estimate of the expected cost of equity. For example, a study by Koedijk et al found that the domestic CAPM only yielded a significantly different estimate from the international CAPM for three percent of firms in their sample.[20] They attribute this to a dominance of country factors in individual stock returns.

One of the key reasons that the international CAPM may not provide a superior estimate of the expected cost of equity is because of the continued existence of home country bias. That is, despite the globalisation of world capital markets, investors continue to favour domestic stocks.[21] This may be partly due to the information

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17 M. Lally (2004a), The Cost of Capital for Regulated Entities: Report Prepared for the Queensland Competition Authority, p.28.

18 The model was originally developed by Solnik. Refer: B. Solnik (1974), “The International Pricing of Risk: An Empirical Investigation of the World Capital Market Structure”, in The Journal of Finance, vol.29, no.2.

19 Strategic Finance Group (2004), The Value of Imputation Franking Credits: Gamma, Report for AGL in Relation to ESC Electricity Distribution Review, p.9.

20 K. Koedijk, C. Kool, P. Shotman and M. van Dijk (2002), “The Cost of Capital in International Financial Markets: Local or Global?”, in Journal of International Money and Finance, vol.21 (6).

21 For example, see: R. Stulz (1999), Globalisation of Equity Markets and the Cost of Capital, National Bureau of Economic Research, NBER Working Papers, 7021.

asymmetries faced by domestic investors considering investments in overseas firms. A survey by Strong and Xu also revealed that fund managers' recommendations were biased towards their home market.[22]

The fact that home bias still exists does not mean that substantial integration of world capital markets has not occurred: what is evident is that the markets are not fully integrated. If markets are not fully integrated, then it is not necessarily appropriate to apply an international CAPM. Certainly, it has not proven a superior model, and until such evidence becomes available (if and when it does), there is no basis for rejecting the domestic CAPM in favour of such an alternative. After considering the estimation difficulties and lack of empirical support to demonstrate the superiority of an international CAPM, over the domestic version, Lally concludes:[23]

> …in the face of an issue like this in which the truth lies somewhere between two models, a conservative approach is desirable, i.e., choosing the model yielding the higher estimate for the cost of capital, on the grounds that understating the cost of capital may lead to businesses failing to invest, and this is the more serious of the two possible errors… Taking account of all these points, I recommend the use of a domestic version of the CAPM.

It has also been suggested that if an international CAPM is not adopted, then all CAPM parameters would need to be respecified as if foreign investors had no influence on the Australian market. However, this suggests that the Australian market is completely segmented from the world market. Given that in reality foreign investors exert significant influence, this is not only virtually impossible to do, but would also abstract from the reality of the practical influences on asset pricing in today's domestic market.

This rate of return is being used to determine prices and will drive investment decisions that are made with regard to current and expected market conditions. It should therefore reflect the rate of return that an investor would require, rather than the theoretical return that an investor would command in either a fully segmented or fully integrated market. As noted above, these parameters should therefore be estimated "as they are".

We have therefore applied the domestic CAPM to determine the cost of equity, estimated using readily observable market data that may be influenced by the presence of foreign investors. Expectations of future returns will be formed based on the actual environment facing investors. Specified in this way, the domestic CAPM does not

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22 N. Strong and X. Xu (2003), "Understanding the Home Equity Bias: Evidence from Survey Data", in Review of Economics and Statistics, vol.85, pp.307-312.

23 M. Lally (2004a), op.cit., p.31.

unrealistically assume complete separation from global markets. The domestic CAPM will therefore serve as a better proxy for the international CAPM, without assuming that the Australian market is fully integrated with world markets.

3.4 Asymmetric consequences of regulatory error

It is widely accepted that regulatory error tends to have asymmetric consequences. The Productivity Commission stated: [24]

> - Over-compensation may sometimes result in inefficiencies in timing of new investment in essential infrastructure (with flow-ons to investment in related markets), and occasionally lead to inefficient investment to by-pass parts of the network. However, it will never preclude socially worthwhile investments from proceeding.
>
> - On the other hand, if the truncation of balancing upside profits is expected to be substantial, major investments of considerable benefit to the community could be forgone, again with flow-on effects for investment in related markets.
>
> In the Commission's view, the latter is likely to be a worse outcome.

In other words, the consequences of setting WACC too low, and discouraging efficient investment in essential infrastructure, are considered worse than setting it too high.

The estimation of WACC is inherently imprecise and hence the probability of specifying a WACC other than the 'true' value is high. For key parameters such as beta and the market risk premium, there is likely to be a range of reasonable estimates rather than a precise value (specific issues in estimating beta are considered in the following section). The Australian Competition Tribunal ('the Tribunal') recognised the range of reasonable outcomes within which a Reference Tariff determination could fall:

> …there is no single correct figure involved in determining the values of the parameters to be applied in developing an applicable Reference Tariff. The application of the Reference Tariff Principles involves issues of judgement and degree. Different minds, acting reasonably, can be expected to make different choices within a range of possible choices which nonetheless remain consistent with the Reference Tariff Principles.[25]

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24 Productivity Commission (2001), Review of the National Access Regime, Report no. 17, AusInfo, Canberra, p.83.

25 Application by GasNet (Australia) Operations Pty Ltd [2003] AcompT 6, para 29.

As noted above, the Tribunal therefore highlighted that the focus of regulatory decision-making should be on the reasonableness of the proposal submitted by the regulated entity. With respect to WACC, this requires an assessment of the extent to which the proposal is within a range of reasonable outcomes.

The possibility that a regulator will reject a reasonable proposal submitted by a regulated entity in favour of its own determination is a key source of regulatory risk. Further, as noted above, there is a high probability that the true value is higher or lower than the estimated value.

Typically, based on our best estimate for WACC we would expect the balance of consequences to be approximately equal (that is, if the consequences of too high a WACC are the same as the consequences of too low a WACC, and the probability of either consequence is the same, the expected value will be zero). However, if the consequences are asymmetric (in this case, the consequence of an under-estimate is worse than the consequences of an over-estimate), then if the probability of either outcome was equal, the expected value will be negative. We therefore need to adjust the probabilities in order to achieve an expected value of zero, which necessitates ensuring that the probability of the worse outcome is lower.

Given the asymmetric consequences of regulatory error, it is therefore important to lower the risk that the true value is higher than the estimated value as this is considered to have more severe social and economic implications.

One possible approach that has been applied to deal with this issue is to specify parameters such as beta, gamma and the market risk premium in terms of a range and then select a point estimate from the upper bound of this range in recognition of the asymmetric consequences of regulatory error. Lally states:[26]

> Given that there is some uncertainty as to the correct parameter estimates, and that the consequences of judging excess profits to exist when they do not is more severe than the contrary error, my view is that one should choose a WACC value from the higher end of the distribution…

This range can be set with reference to empirical evidence. Alternatively, a probability distribution of estimates can be determined. For example, in estimating beta for the gas industry the New Zealand Commerce Commission determined a point estimate for beta (which was based on comparable companies) and then assigned a standard deviation to the estimate.[27] In determining the regulated WACC it then selected a

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[26] M. Lally (2004b), The Weighted Average Cost of Capital for Gas Pipeline Businesses, Report Prepared for the New Zealand Commerce Commission, University of Wellington.

[27] New Zealand Commerce Commission (2004), Gas Control Inquiry: Final Report.

value from the 75th percentile of the distribution, which implies that there is only a 25% probability that the true WACC is higher than this selected value.

Another means of specifying the probability distribution is by using techniques such as Monte Carlo analysis. This technique can also be used as a 'reasonableness check' against specified ranges, which has been done by both the ACCC and the QCA (although this technique still requires a degree of judgment to be applied in determining the inputs to be used).

In conclusion, it is important to give due regard to the imprecise nature of WACC estimation and the more severe consequences which can arise if the regulated WACC underestimates the true value. Analysis will generate a range of reasonable estimates for key parameter values (particularly beta and the market risk premium). Consideration of the asymmetric consequences of regulatory error would suggest the need to select estimates between at least the mid-point and the upper bound of this range.

4 Parameter estimates

We will now consider estimation of the following parameters:

- the risk-free rate;
- capital structure;
- the cost of equity;
- the cost of debt; and
- gamma.

4.1 Risk-free rate

The risk-free rate measures the return an investor would expect from an asset with zero volatility and zero default risk. The yield on long-term Australian Commonwealth Government bonds is the best proxy for a risk-free return as the government can honour all interest and debt repayments.

There are a number of issues to consider with respect to the risk-free rate:

- the bond maturity;
- the length of the averaging period;
- the treatment of compounding; and
- review prior to the final decision.

4.1.1 Bond maturity

The ten-year Commonwealth Government bond is now generally accepted as the standard benchmark in regulatory decision-making (and is typically also applied in commercial applications, unless the horizon of a particular asset or project is very short). This is consistent with the long-term forward-looking horizon over which it is assumed investors are forming their return expectations under the CAPM. In Australia, the ten-year bond is the longest liquid maturity currently available.

We have therefore used the ten-year Commonwealth Government bond to determine the risk-free rate for this analysis.

4.1.2 Averaging period

Given the CAPM is intended to reflect expectations as of the day of analysis, it is theoretically correct to base the risk-free rate on the prevailing yield on the date of the valuation. However, problems may occur if there is a spike in yields on the day that the rate is applied. It is therefore now common regulatory practice to average the rate over a short horizon, which typically ranges from between ten and forty days. The AER's Principles provides that the regulated entity can select an averaging period of between five and forty days, although over such a short horizon the choice of averaging period is likely to be of little consequence.

We have used a period of forty days, as previously adopted by GasNet, ending on the 26th of February 2007. The average risk-free rate over this period was 5.85%.

4.1.3 Treatment of compounding

Published bond rates, including the Commonwealth Government bond rate, tend to be quoted as nominal rates, compounding semi-annually. These rates cannot be directly compared with rates that have a different compounding frequency (say, quarterly or annually). The CAPM framework is a single period model and hence no assumptions are made regarding compounding. Further, the market portfolio that underpins CAPM is assumed to comprise *all* risky investments, which will have various compounding frequencies (with some investments only generating a return at the end of the term of that investment). Given the obvious practical difficulties associated with constructing the market portfolio, a domestic sharemarket index tends to be used as a proxy.

It could be argued that an adjustment should be made to the risk-free rate for the effects of compounding (a similar adjustment would also need to be made to the corporate bond rate used to determine the debt margin, and it could also be argued that the adjustment should also be made when calculating the market risk premium). A relatively simple alternative is to convert the rate to an annual effective rate. [28] Annual effective rates that have been converted from nominal rates of different compounding frequencies are readily comparable.

We note the potential issues associated with compounding however we have not sought to make any adjustments to the rate.

[28] The formula for this conversion is: Annual effective rate = [1+(nominal rate/number of compounding periods)]^number of compounding periods per annum – 1. Given a 5.85% risk free rate and semi annual compounding, the annual effective rate would be 5.94% or some 9 basis points higher than the nominal risk free rate.

4.1.4 Review prior to final decision

The other key consideration for regulatory decision-making is the environment in which the rate is set, as the risk-free rate will fluctuate with the economic cycle. The interest rate environment leading up to a draft decision is likely to be different from the environment leading up to the final decision. As prices should reflect the economic environment prevailing at (or close to) the commencement of the new regulatory period, the rate should be reset prior to the final decision. Another reason for doing this is that the regulated entity may wish to implement hedging strategies for underlying borrowings prior to the commencement of the new regulatory period, which ideally should be implemented in the same market environment within which the risk-free rate is set.

If there is an intention to reset the risk-free rate prior to release of the final decision, then GasNet should be given confidential notice of this at least ten days prior to the commencement of that reset period and well in advance of the release of the final decision.

4.2 Capital structure

4.2.1 Methodology

The assessment of capital structure for the purpose of WACC is based on an assessment of an 'optimal' long-term target capital structure for the firm given its risk profile and the business within which it operates. For the purpose of this analysis, capital structure is measured in terms of debt to total value. It should also be expressed in market value terms, rather than book values, however this cannot necessarily be readily observed for all firms, particularly for debt.

While the determination of a firm's target capital structure is typically a detailed process that considers both industry environment and firm-specific factors, the analysis for the purpose of the regulated WACC is typically limited to an examination of appropriate comparators (given this is seen to be indicative of the sustainable capital structure for a firm operating in the relevant industry), as well as regulatory precedent. These are now considered below.

4.2.2 Analysis

Using data from Bloomberg, we have examined firms categorised as being engaged in either gas transmission or distribution. These firms have been sourced from a number of jurisdictions, with US firms dominating the sample. Caution must be exercised in making comparisons between jurisdictions, including interpreting averages across them, given that different industry and regulatory environments will influence the level of debt that can be sustained by firms in each jurisdiction. It is also possible that these firms engage in activities other than gas distribution, although this should be their primary business activity.

Where possible, we have collected data on the average debt to value ratio over the past five years. This is considered more robust than taking an estimate from a single point in time, as this will be sensitive to the firm's current stage in its investment cycle. Adequate data could only be obtained for the category "Gas Distribution".

Data for three Australian gas distribution firms are summarised in the following table:

Table 2 Australian gas distribution firms: capital structure (over previous 5 years)

Company	Average debt to total value
Alinta	30%
Envestra	65%
AGL[a]	30%

a AGL is an integrated energy business. In addition to its interests in gas, it is involved in retail and merchant energy and power generation.

Source: Bloomberg

Observations for gas distribution firms across all jurisdictions are summarised in Table 3 (this includes the Australian firms included in Table 2). For data by firm, reference is made to the table in Appendix A, which details all comparable companies used in the beta analysis.[29]

Table 3 Sample of global gas distribution firms: capital structure (over previous 5 years)

Sample	Average debt to value	Low	High	Standard deviation	Number of firms within 1 standard deviation of mean
All firms (n=58)	36%	0	78%	18%	38
US only (n=22)	43%	0	70%	11%	15

Source: Bloomberg

A review of capital structure decisions for regulatory decisions in energy are summarised in the following table. In all decisions the value determined is 60%.

[29] It should be noted that not all of the firms maintained for the purpose of the capital structure review are included in the sample in the Appendix, as firms whose betas were not statistically significant were excluded from that analysis.

Table 4 Capital structure assumptions: energy decisions

Decision	Debt to total value
ACCC	
Amadeus Basin to Darwin (2002)	60%
Moomba to Sydney (2002)	60%
Electricity transmission (Powerlink, ElectraNet, Vencorp, SPI PowerNet - 2002)	60%
MurrayLink (2003)	60%
Energy Australia (2005)	60%
Transgrid (2005)	60%
Moomba to Sydney (2005)	60%
Roma to Brisbane (draft, 2006)	60%
AER	
Directlink (2006)	60%
ESC	
Gas distribution (2002)	60%
Electricity distribution (2005)	60%
ESCOSA	
Electricity distribution (2005)	60%
Gas distribution (2006)	60%
IPART	
Electricity distribution (2004)	60%
AGL (2005)	60%
CEG (2005)	60%
QCA	
Electricity distribution (2005)	60%
Envestra and Allgas (2006)	60%

4.2.3 Conclusions

There is compelling regulatory precedent for a capital structure of 60% for GasNet, notwithstanding this is higher than the average capital structures maintained by other gas distribution firms in the industry in the past five years. While we are of the view that a value of 60% is not unreasonable, the industry evidence shows that there is no justification for a higher value. We have therefore assumed 60% for the purpose of our analysis.

4.3 Cost of equity: methodology

4.3.1 Methodology

The most commonly applied approach to estimating the cost of equity is the CAPM. As CAPM is a forward looking model, parameter estimates are derived based on expected values. Under the CAPM the required return on equity is expressed as a premium over the risk free return as follows:

$$E(R_e) = R_f + \beta_e * [E(R_m) - R_f]$$

where:

R_e = the cost of equity capital

R_f = the risk free rate of return

$[E(R_m) – R_f]$ = the market risk premium

E( ) indicates the variable is an expectation and

β_e = the systematic risk parameter (equity beta).

The CAPM produces a post-tax nominal measure of the cost of equity.

The beta in the above equation is an equity beta which represents the sensitivity of the operating cash flows generated by the assets of an entity adjusted for the effect of that entity's gearing (representing financial risk) to changes in general economic conditions compared with the market.[30]

Given that the risk free rate is readily observable (based on long-term government bonds), the two key parameters relating to the cost of equity are:

- equity beta; and
- market risk premium.

These parameters are considered in turn.

[30] A value of less than one indicates the entity's operating cash flows are less sensitive than the market as a whole to changes in economic conditions whereas a value greater than one indicates greater sensitivity than the market as a whole.

4.4 Equity beta

As noted above, we have applied the domestic CAPM to determine the cost of equity , which derives parameter estimates based on expected values. To the extent that the analysis involves comparisons with other companies, the standard approach is to use asset betas, which remove the impact of financial risk.

We have applied the Monkhouse formula for converting between asset and equity betas as this is the approach that has typically been used by the ACCC.[31] This is specified as follows:

$$\beta_e = \beta_a + (\beta_a - \beta_d) * \{1-[R_d/(1+R_d)] * [T_c * (1 - \gamma]\} * D/E$$

where:

β_a = beta of assets

β_d = beta of debt

R_d = the cost of debt capital

T_c = corporate tax rate

γ = gamma

D/E = value of debt divided by the value of equity.

This same approach is also used to 'relever' an asset beta to produce an equity beta, which re-incorporates financial risk based on the target level of gearing for the relevant entity.

4.4.1 Debt beta

The Monkhouse approach includes a parameter for the beta of debt. A common approach to estimate the debt beta is using the structure of the CAPM:

$$\beta_d = (R_d - R_f)/(E(R_m) - R_f)$$

This has the appeal of using a familiar relationship between a beta and the market risk premium ($E(R_m) - R_f$). The approach attributes the debt risk premium (R_d - R_f) to systematic risk. However, a substantial determinant of the cost of debt is default risk, and it therefore unrealistic to assume the debt risk premium is related to movements only in the market.

The alternative approach is to assume the debt beta is zero. The systematic risk of debt is considered extremely low. In practical terms, when investors are pricing debt

[31] The key issue with converting between equity betas and asset betas is to apply a consistent approach at all times.

securities, their key concerns will be credit and liquidity risks, rather than systematic risk. Attempts in the literature to estimate systematic risk of debt indicate that even with companies that have little apparent risk of default, the returns to the debt are virtually independent of the returns on the market index.

Debt beta determinations in recent energy decisions are provided in the following table:

Table 5 Debt beta assumptions: energy decisions

Decision	Debt beta
ACCC	
Amadeus Basin to Darwin (2002)	0.15
Electricity transmission (Powerlink, ElectraNet, Vencorp, SPI PowerNet – 2002)	0
Energy Australia (2005)	0
Transgrid (2005)	0
Moomba to Sydney (2005)	0
Roma to Brisbane – draft (2006)	0
AER	
Directlink (2006)	0
ESC	
Gas distribution (2002)	-
Electricity distribution (2005)	-
ESCOSA	
Electricity distribution (2005)	-
Gas distribution (2006)	-
IPART	
Electricity distribution (2004)	0-0.06
AGL (2005)	0
CEG (2005)	0
QCA	
Electricity distribution (2005)	0.12
Envestra and Allgas (2006)	0.1

Lally recommends the application of a debt beta of zero in a regulatory context:[32]

> …on account of the difficulties in estimating the debt beta, the slightness of the error in treating it as zero, the likelihood that the resulting errors are less than those arising from the Authority's current approach, and the likelihood that the errors will be of the less serious type than those arising from the Authority's current approach.

32 M. Lally (2004a), op.cit, p.75.

We concur with the arguments supporting a zero debt beta and accordingly, we have adopted a value of zero.

4.4.2 Estimation of beta: methodology

Approaches

There are three basic approaches to estimating systematic risk:

- direct estimation;
- first principles; and
- comparable companies.

We have employed all three methods in our analysis of GasNet's WACC.

Estimation error

Before progressing to the more detailed analysis, it is important to be aware of the susceptibility of beta to estimation error. Beta estimates are obtained based on a statistical analysis of two data series (being the historical returns on the firm's shares and the market index). There can be considerable 'noise' in both of these datasets, which can result in measurement error.

An important issue that is commonly encountered is thin trading and this is particularly significant here given GasNet's shares were not frequently traded. Thin trading tends to underestimate a firm's beta given its share price can appear to have a deceptively low variance relative to the market. This can mean that any resulting estimates cannot be relied upon as meaningful measures of the firm's systematic risk. Techniques such as the Scholes-Williams and Dimson adjustments can be used however they do not necessarily improve the quality of the estimates.

There are a number of other possible sources of estimation error, including:

- sensitivity of estimates to the return interval;
- the influence of outliers;
- misspecification of the market portfolio; and
- the tendency for firms' betas to revert towards the market mean of 1 over the long-term.

While there are potential means of dealing with these issues, the techniques may (or may not) improve the quality of the estimates and will not eliminate susceptibility to error.

A brief review of measurement error, including the problem of thin trading, is contained in Appendix B.

As outlined above, it is generally recognised that regulatory error has asymmetric consequences. While it is important to give due regard to this principle when setting all WACC parameters, it is particularly important here. The susceptibility of beta estimation to error means that a cautious approach should be undertaken. For example, once a reasonable range of estimates is determined, the point estimate used to calculate WACC could be selected from the upper quartile of this range.

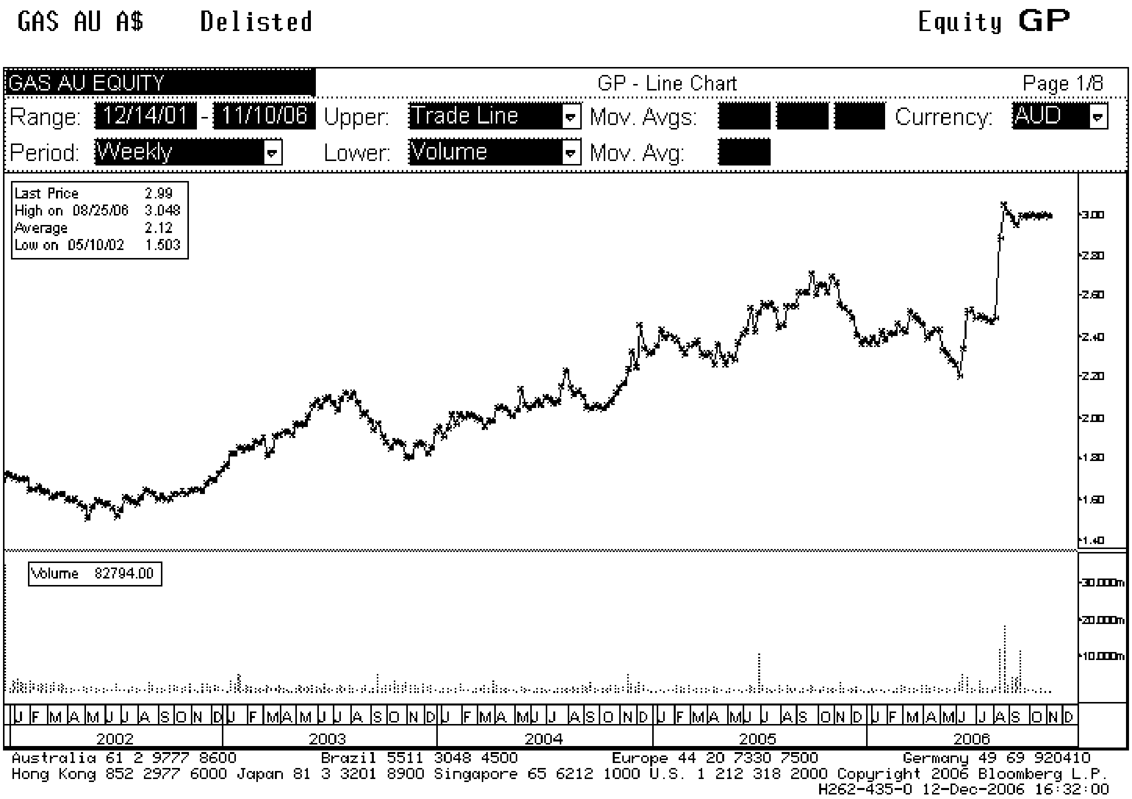
4.4.3 Estimating GasNet's Beta: Direct Estimation

Analysis

GasNet was listed in December 2001. It was delisted on the 17th of November 2006, following its acquisition by the Australian Pipeline Trust. There may be some benefit in reviewing GasNet's historical beta estimate, so we have sought to calculate this by performing a regression of the return on GasNet's shares against the return on the ASX 200 Index.

As noted above, one of the key difficulties in estimating GasNet's WACC is thin trading, which is likely to lead to an under-estimation of GasNet's beta. Figure 3 tracks GasNet's share price since December 2001. The data series at the bottom of this chart shows the daily trades in the stock. Turnover volumes over the majority of this period are barely discernible. Most of the activity that has occurred has been around the dates of key announcements during the takeover process.

Figure 3 GasNet's recent share price history



Data source: Bloomberg

As noted above, one of the main consequences of thin trading is that the beta will be under-estimated. This is because one price change can reflect a series of events. As a consequence, the share price may appear to be less volatile than the market. Dimson notes:[33]

> Unfortunately, infrequent trading will bias beta estimates so as to cause the estimates to appear stable. Infrequently traded securities will have low beta estimates, while frequently traded securities will have high estimates. Provided that frequency of trading is serially correlated, the beta estimates will be relatively stable, regressing somewhat to the mean.

33 E. Dimson (1979), "Risk Measurement when Shares are Subject to Infrequent Trading", in Journal of Financial Economics, Vol.7, p.221.

Techniques such as the Scholes-Williams and Dimson adjustments seek to address the problems associated with thin trading. Unfortunately, in practice, they do not always improve the performance of the estimate. Gray et al observe:[34]

> However it is likely…that the Scholes-Williams beta will perform even worse than the OLS beta estimate… A Scholes-Williams beta, however, is potentially less precise and contains more estimation error than a standard beta, due to the additional parameters that must be estimated. More specifically, the measurement error associated with a Scholes-Williams beta is a culmination of the errors present in each of the three beta estimates of which it is comprised. Nonetheless, given that some data providers, such as CRIF, rely on the Scholes-Williams procedure as one adjustment technique, it is probably worthwhile investigating.

With these difficulties in mind, we have estimated GasNet's beta using monthly data since January 2002 through to May 2006 (which was prior to the takeover announcement). This results in 53 monthly observations. While we would prefer to use 60 monthly observations, we believe that it is necessary to truncate the series on this date given the 'noise' that the takeover announcement will introduce into the share price. The results are shown in the following table.

Table 6 GasNet's Equity Beta: Not Adjusted for Infrequent Trading

Equity Beta	R^2	Standard error	t statistic
0.24	0.04	0.18	1.34

Source: Bloomberg

This result is not statistically significant and therefore cannot be relied upon.

We have also sought to adjust for the possible lagged effects that can arise as a result of thin trading using both the Scholes-Williams technique and the Dimson adjustment. The Scholes-Williams technique produced a revised estimate of 0.11 however it is not statistically significant. The Dimson adjustment also produced an estimate of 0.11, which also cannot be considered reliable as the coefficients of the lead and lag betas are not significant and one is negative. As noted above, these poor results are not necessarily surprising.

Given the estimates are not statistically significant, we have not sought to further improve the beta estimate using the Blume adjustment (which is a recommended technique to adjust for the possible effects of mean reversion).

34 S. Gray, J. Hall, R. Bowman, T. Brailsford, R. Faff, R.Officer (2005), ibid., p.40.

The other issue to note with respect to this analysis is that GasNet's beta will reflect the risk profile of its other business activities, which are not regulated. As outlined in Section 2.1, GasNet's revenue remains dominated by the regulated Victorian business, with the pipeline in WA contributing its first full year of revenue in 2005. While this pipeline is not regulated, this revenue is underpinned by fixed price take-or-pay contracts, which could actually have a lower risk profile than GasNet's regulated activities. We have therefore not sought to adjust GasNet's beta estimate for these other activities.

Conclusions: direct estimation

This analysis has confirmed the significant difficulties presented by thin trading. While we have presented this analysis for the purpose of completeness, the results are essentially meaningless and therefore must be disregarded.

As we can place no reliance on these results, they will not be taken into account as part of our overall assessment of GasNet's beta. The focus of the analysis will therefore need to revert to a first principles assessment and comparable companies analysis.

4.4.4 Estimating GasNet's beta: first principles analysis

Background

A first principles analysis is a qualitative assessment of GasNet's risk profile, the aim of which is to identify its systematic (or non-diversifiable) risk factors and assessing their likely impact on the asset beta. Lally identifies a number of factors to be considered here, including[35]:

- nature of the product or service;
- nature of the customer;
- pricing structure;
- duration of contracts;
- market power;
- nature of regulation;
- growth options; and

[35] M. Lally (2004a), op.cit.

- operating leverage.

A number of these factors are interrelated – that is, the impact of one factor on beta could either be increased or lessened by another factor. Hence, while the impact of each factor can be considered in isolation, the overall assessment will reflect the net impact of the factors in combination. The first two factors are closely linked and so will be considered together.

Nature of the product/nature of the customer

For the purpose of beta, the objective of understanding the underlying market for the relevant product is to identify the key drivers of demand and the extent to which these drivers have a relationship with domestic economic activity.

Overall, gas is one of a number of alternative energy sources, so the demand for gas firstly needs to be considered within the context of the overall demand for energy. As noted in section 2.1, ABARE bases its forecasts for the demand for energy on the outlook for economic growth, and is expecting long-term energy demand growth in Victoria to be relatively subdued compared to some of the other states. It also notes that the energy intensity of industry has been declining, whereas the consumption of energy per person is expected to rise.

The demand for gas then depends on its competitiveness relative to other energy sources. As cited above, gas comprises around 18% of Victoria's overall energy consumption, a share which has fallen since the 1990s.

In terms of residential energy consumption, ABARE has predicted that gas is expected to maintain a reasonably constant share over the longer term. As electricity has long remained the dominant energy source, alternatives such as gas are regarded as more risky. This conclusion was made by the QCA in its recent decision relating to gas distribution:[36]

> The Authority is of the view that, in many instances, gas is a fuel of choice, while everyone generally connects to electricity. Because it is a fuel of choice, it faces competition from other sources of energy such as electricity and LPG. As such, the Authority accepts that the gas distributors will be subject to a greater level of systematic risk than the electricity distributors and that a higher equity beta is justified.

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[36] Queensland Competition Authority (2006), Final Decision – Revised Access Arrangement for Gas Distribution Networks: Allgas Energy, p.75.

The relationship between demand and economic activity will also be driven by the underlying composition of the customer base. Approximately 55% of GasNet's revenues are accounted for by Tariff V customers, which are small residential and commercial customers. Overall, residential demand for energy is likely to be less sensitive to economic activity than industrial/commercial demand.

For example, an Australian study by Akmal and Stern, showed that residential electricity demand is price and income inelastic, whereas residential gas demand has a zero price elasticity but an income elasticity that is greater than one (which may also reflect that it is a 'fuel of choice' as proposed by the QCA).[37]

It is income elasticity that is of particular relevance in assessing systematic risk. This is because incomes will have some correlation with domestic economic activity. A positive income elasticity therefore creates a clear linkage between domestic economic activity and product demand.

The other key driver of residential demand for gas is weather, with the Victorian market demonstrating particular sensitivity to variations in winter temperature compared to average, however this risk is not systematic in nature.

Commercial and industrial demand, will be more sensitive to economic growth, with the longer-term trend influenced by changes in the energy intensity of industry. Large customers account for approximately 45% of GasNet's revenues and this does not include smaller commercial customers, who are likely to be more sensitive to economic activity. Hence, this shows that overall, any changes in demand by industrial and commercial users could have a reasonably significant impact on GasNet's revenues.

It can therefore be concluded that the demand for gas will have a positive relationship with economic activity given the income elasticity of residential demand and the sensitivity of commercial and industrial demand to growth. The ultimate impact of this on GasNet's systematic risk profile will depend on the form of regulation and contracting arrangements, which is discussed further below.

Pricing structure

GasNet's charges are based on regulator-approved reference tariffs. As the Victorian market operates on a market carriage basis, charges are levied on a usage basis. This means that GasNet's sales remain fully exposed to changes in volumes.

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37 M. Akmal and D. Stern (2001), The Structure of Australian Residential Energy Demand, Working Papers in Ecological Economics, The Australian National University, Canberra.

There are certain pass-through events that are allowed for under the access arrangement, including the imposition of minimum standards, changes in the nature or scope of services and changes in the way in which GasNet must undertake its services. However, apart from efficiency, economic factors are likely to be the key driver of cost changes through time.

Overall, therefore, the pricing structure provides little if any protection for GasNet's revenues from volume changes. This will suggest a higher value for beta.

Duration of contracts with customers

As Victoria operates on a market carriage basis there are no contracts with customers. This is different from the situation facing gas providers in a number of other states, where revenues are protected by contracts with take-or-pay provisions.

This lack of contractual certainty significantly increases GasNet's exposure to volume risk, which as we have shown above, has drivers that are systematic in nature.

Market power

As GasNet owns all of the key gas transmission assets in Victoria, it will possess market power in the Victorian gas market, although this is tempered by:

- the availability of substitutes for gas as an energy source, including electricity which is likely to remain the most dominant; and
- the significant concentration on the buyer side (via retailers and distributors).

Lally observes:[38]

> In respect of gas pipeline businesses, they seem to be local monopolists but their monopoly power may be diluted by the counterveiling power of their large customers and the presence of competing power sources. So, if monopoly power affects beta, then the effect of any such counterveiling power and competing energy sources would be to mitigate that beta effect.

Market power tends to have a dampening effect on beta. In this case, however, any market power that GasNet may have been seen to naturally possess is diluted, which would serve to neutralise any impact that market power would otherwise have on beta.

[38] M. Lally (2004b), op.cit., p.36.

Nature of regulation

GasNet's systematic risk will be affected by the form of regulation, as this determines its exposure to volume risk. GasNet's regulatory framework represents a form of average revenue control with bounds beyond which a review of prices would be triggered (ie, for extreme events). While this may be seen to provide a degree of revenue protection, particularly compared to a pure price cap, GasNet still remains exposed to systematic volume risk.

Overall, however, it is noted that historically regulators have not sought to explicitly attribute any increment in the asset beta for a price cap over a revenue cap (and vice versa) and accordingly the implications of the form or regulation for beta remain unclear. What this may suggest is that if a range of reasonable outcomes for beta is identified, a form or regulation that retains exposure to systematic volume risk suggests that the point estimate should be selected from the upper quartile of this range (in addition to recognising the asymmetric consequences of error).

In this regard, it will be important to examine other regulatory decisions, including the extent to which the form of regulation has been factored into the assessment of beta. This is considered below as part of the comparable companies analysis.

Growth options

Growth options refer to the potential to undertake significant new investment, particularly in new areas or products. Chung and Charoenwong argue that businesses that have a number of valuable growth opportunities, in addition to their existing assets (or 'assets in place'), will tend to have higher systematic risk compared to firms that don't have these opportunities.[39]

The impact of growth options on beta in a regulatory context is not necessarily clear. If this assessment was based on the analysis of an efficient benchmark firm (that was not regulated), it could be argued that the implications of growth options need to be recognised, regardless of the impact that regulation has on the value of the firm and its risk profile. Alternatively, if the existence of regulation is recognised as part of the assessment, then the presence of growth opportunities may arguably be excluded.

Overall, GasNet is unlikely to have opportunities for growth via new products. Its growth options will be limited to opportunities to expand the network in Victoria. We

[39] K. Chung and C. Charoenwong (1991), "Investment Options, Assets in Place and the Risk of Stocks", in Financial Management, Vol.3.

are therefore of the view that growth options are not likely to have a discernible impact on GasNet's systematic risk.

Operating leverage

Like other gas transmission businesses, GasNet's costs are mainly fixed, with the exception of fuel costs. High operating leverage is associated with higher systematic risk, as these fixed costs will still be incurred irrespective of actual volumes (and revenues).

As this first principles analysis is being used to determine where GasNet would be positioned with respect to a range of beta estimates sourced from comparators, the impact of operating leverage on this decision will depend on GasNet's operating leverage relative to these comparators. Unfortunately there is limited data available to enable an assessment of the actual operating leverage of these other firms.

We have no evidence to suggest that GasNet's operating leverage is any different than a typical gas transmission firm. The sample we have used in the comparable companies analysis largely comprises gas distribution firms, which overall, should generally exhibit similar operating leverage to gas transmission. There may be some differences, for example, gas distribution firms can suffer gas loss, which is essentially a variable cost (transmission firms don't suffer these losses). Given any such losses would depend on the state of the distribution network it is difficult to draw any general conclusions here, and it is possible that the overall impact is marginal.

Conclusions: first principles analysis

In conclusion, we can observe that:

- demand for gas is to some extent systematic in nature, given that:
  - residential demand has a positive income elasticity (which in turn, will be positively related to domestic economic growth); and
  - industrial and commercial demand will have some relationship with domestic economic activity;
- Victoria operates on a market carriage basis, meaning that GasNet's sales are fully exposed to changes in volumes. Little protection is provided by the pricing structure;
- the form of regulation applied to GasNet means that it retains some exposure to systematic volume risk. While the implications of the form of regulation for beta

are unclear, this would provide further support for selecting a point estimate for beta from the upper quartile of a reasonable range;

- the impact of market power and growth options on GasNet's beta is likely to be minimal; and
- GasNet has high operating leverage, which is a significant contributor of systematic risk. However, to the extent that beta is being assessed against other businesses with similar operating leverage, a specific adjustment for this would not be made.

We can therefore conclude that GasNet is exposed to risk that is systematic in nature. While this first principles assessment is purely qualitative, we can use this to potentially refine any conclusions emerging from the comparable companies analysis, which now follows.

4.4.5 Estimating GasNet's beta: comparable companies

Methodology

Comparable companies analysis involves examining betas for firms in either the same or similar industry to the firm being reviewed. We sourced data from Bloomberg from the following industry categories:

- gas transportation;
- gas distribution; and
- electricity transmission.

In compiling the sample, we reviewed the company descriptions to ensure that the main business activities of the firm are sufficiently relevant to GasNet. The other key requirement is for the sample to be statistically sound, given the issues with estimation error that were outlined above. Despite the filters being applied here, estimation error will remain an issue and needs to be kept in mind when drawing any conclusions from the analysis.

The filters applied were as follows:

- at least five years of monthly data is necessary for each firm. We applied a minimum threshold of 58 observations (monthly data);
- beta estimates with a t-statistic of less than 2 were excluded; and
- beta estimates with a R^2 of less than 0.1 were excluded.

Unfortunately a number of relevant firms had to be eliminated from the sample due to the poor statistical quality of the estimates. This included all of the firms in the gas transportation category, and the three Australian firms in gas distribution (being AGL, Envestra and Alinta). Only three firms remained in the electricity transmission sample after the filters were applied, and all are Latin American. We have therefore not considered these estimates here.

In the absence of data for gas transmission, gas distribution is considered an appropriate proxy. One of the main distinctions that has been drawn between gas transmission and distribution is that gas transmission revenues are often supported by long-term take-or-pay contracts, however as noted above, that is not the case here.

A complete list of the companies comprising the final sample is provided in Appendix A. For each company, we have presented the R^2, standard error and t statistic.

As discussed in the section on capital structure analysis, caution needs to be exercised when referencing firms from other jurisdictions, given the potential differences in industry structure and regulation.[40] This is particularly the case when interpreting averages across jurisdictions. We would therefore recommend reviewing the individual estimates in addition to the averages.

As noted above, one of the recommended techniques for potentially improving the reliability of estimates is the Blume adjustment (for example, this technique is applied by Bloomberg). We have therefore applied this adjustment to all of the firms in the sample before calculating the asset beta. We provide both raw betas and Blume-adjusted betas in our results. While the raw estimates reflect what the betas of these companies have been historically, the Blume-adjusted estimates provide an indication of how these betas could be expected to vary in the longer term (and hence should also provide a more appropriate benchmark for a long-term forward-looking estimate).

Results

The sample of gas distribution firms included 29 companies. Again, we have calculated a separate average for the US firms given they comprise 11 out of the 29 firms in the sample.

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40 There is no generally accepted method for adjusting estimates derived from international comparators, although subjective adjustments are sometimes made. Given the application of such subjective judgements could risk compounding existing issues with estimation error, we have not sought to make any specific adjustment here. However, due regard needs to be given to potential differences when drawing any conclusions as to where GasNet might be positioned relative to these comparators.

For firms to be included in Bloomberg's 'Gas Distribution' classification, this must represent their main business activity. However, a number of firms are engaged in other activities, such as electricity (we eliminated firms that engaged in significantly different activities). We therefore estimate the average for a further sub-group of firms that appear to only operate in the gas industry.

The results are shown in the following table.

Table 7 Global gas distribution firms: average beta estimates

Sample	Average asset beta	Low	High	Standard deviation	Number of firms within one standard deviation of mean
Raw betas					
All firms (n=29)	0.50	0.21	1.04	0.20	21 (72%)
US only (n=11)	0.43	0.32	0.60	0.10	8 (73%)
Gas only (n=11)	0.49	0.29	1.04	0.21	10 (91%)
Blume-adjusted betas[a]					
All firms (n=29)	0.54	0.28	0.99	0.18	20 (69%)
US only (n=11)	0.46	0.37	0.62	0.09	8 (73%)
Gas only (n=11)	0.52	0.37	0.99	0.18	10 (91%)

a The raw equity beta of each firm was Blume-adjusted prior to calculating the asset beta.
Note: Assumes a debt beta of zero.
Source: Bloomberg

Assuming a capital structure of 60%, the equivalent equity betas for each of these averages are:

- all firms: 1.24 (raw), 1.33 (Blume-adjusted)
- US only: 1.06 (raw), 1.14 (Blume-adjusted)
- gas only: 1.21 (raw), 1.28 (Blume-adjusted).

This data suggests that there is a reasonable probability that the equity beta for a firm operating in the gas industry is greater than 1.

Regulatory decisions

Asset and equity beta outcomes from relevant regulatory decisions are summarised in the following table.[41]

[41] As shown in Table 4 above, a capital structure of 60% was applied in all decisions. Any relative differences between asset and equity beta outcomes will therefore be due to the use of different delivering/relevering approaches.

Table 8 Asset and equity betas: relevant regulatory decisions

Decision	Asset beta	Equity beta
ACCC		
Amadeus Basin to Darwin (2002)	0.5	1.0
Moomba to Sydney (2002)	-	1.0
Electricity transmission (Powerlink, ElectraNet, Vencorp, SPI PowerNet – 2002)	0.4	1.0
MurrayLink (2003)	0.4	1.0
Energy Australia (2005)	0.425	1.06
Transgrid (2005)	0.45	1.12
Roma to Brisbane (draft, 2006)	-	1.0
AER		
Directlink (2006)	-	1.0
ESC		
Gas distribution (2002)	-	1.0
Electricity distribution (2005)	-	1.0
ESCOSA		
Electricity distribution (2005)	-	0.8
Gas distribution (2006)	-	0.8 – 1.0
IPART		
Electricity distribution (2004)	0.35-0.45	0.78–1.11
AGL (2005)	0.3-0.4	0.8-1.0
CEG (2005)	0.3-0.4	0.8-1.0
QCA		
Electricity distribution (2005)	0.45	0.90
Envestra and Allgas (2006)	0.55	1.1

This shows that in the main, regulators have adopted an equity beta of 1 for energy decisions, including distribution and transmission, which approximates the beta of the market as a whole. An equity beta of 1 is also recommended under the AER's Principles. Assuming capital structure of 60% and applying the Monkhouse formula, this represents an asset beta of 0.4.

There are a couple of notable recent departures from this, both of which are in gas. First, the QCA adopted a higher asset beta in its recent decision relating to Allgas and Envestra. In contrasting this decision with its determination for electricity distribution, as noted previously, it views gas as a 'fuel of choice' and therefore that it has fundamentally higher systematic risk than electricity. In addition, Allgas and Envestra were seen to have a different customer profile relative to other states, with a higher proportion of commercial and industrial customers.

Second, the most recent decision by ESCOSA went the other way, proposing an equity beta range of 0.8 to 1, with a mid-point of 0.9. This rejected a revised equity beta range submitted by Envestra of 0.9 to 1.1 - that is, that range was not considered reasonable. It even went against the advice of its own consultant, the Allen Consulting Group (ACG), which concluded that a range of 0.8 to 1.1 was appropriate, and that if a point estimate were to be adopted it should be 1.

In its Final Decision, ESCOSA does not provide sufficient rationale for rejecting the range submitted by Envestra (with the range submitted by its own consultant falling within this same range), but rather relied on evidence from work undertaken by Gray and Officer as part of its review for ETSA Utilities, which inferred an equity beta of 0.9. Given the imprecise nature of beta estimation, the asymmetric consequences of regulatory error, the similar positions concluded by both ACG and Envestra and finally, significant regulatory precedent, ESCOSA's decision to reject Envestra's proposal is highly questionable.

Impact of form of regulation

As noted above, the form of regulation can have implications for the assessment of systematic risk. However, an examination of the data in Table 8 shows that this has not necessarily been reflected in beta outcomes for regulated businesses. Table 8 covers a spectrum of regulatory decisions from the energy industry. Electricity transmission network service providers, for example, which are subject to revenue caps, have received an equity beta of 1 (which has now effectively been entrenched in both the AER's Principles and the new National Electricity Rules).

Decisions with respect to gas, which tend to have been subject to some form of price cap, have been more variable, ranging between 0.9 and 1.1. All other things being equal, if the form of regulation was being taken into account by regulators, then in theory, the beta outcomes observed for gas businesses should be higher than the precedent beta of 1 for electricity transmission, although this has not necessarily always been the case.

There is therefore limited evidence to suggest that the form of regulation has influenced regulators' assessment of beta. This was highlighted in the Envestra decision, where ESCOSA accepted the advice of its consultant, the ACG, which was that:[42]

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[42] ESCOSA (2006), Proposed Revisions to the Access Arrangement for the South Australian Gas Distribution System, p. 70.

> …it is difficult to make fine distinctions in the equity beta for matters like the form of price control that is applied to a particular regulated entity, noting ACG's view that:
>
> - there is no empirical evidence concerning the impact on beta of price cap and revenue cap form of regulation and so any adjustment applied is speculative;
> - the form of price control is one of the factors that may differ between Envestra's South Australian gas distribution business and other regulated energy distributors, and it cannot be known whether adjusting for one factor may improve the estimate; and
> - it has not been the practice of Australian regulators to adopt different betas depending on the form of price control…

ACG also refuted any implication that the QCA had taken the form of regulation into account in its decisions with respect to Allgas and Envestra, but rather that:[43]

> …the differential in Queensland between gas and electricity was not based on a revenue cap *per se* and price cap regulation, but on the *specific* regulatory arrangements applied by the QCA to Queensland electricity distribution, which included a government policy of absorbing changes in distribution prices rather than allowing these to be passed through to customers.

In its decision with respect to Envestra, the QCA indicated that the form of regulation does have some impact on systematic risk, although it stated that this was only slight.[44]

In its final decision with respect to GasNet the ACCC cited comments from its consultant, also ACG:[45]

> …we would caution against attempting to make ad hoc adjustments to proxy betas on account of perceptions of differences in non-diversifiable risk given the absence of empirical evidence on the size of the required adjustment (and whether any adjustment may be warranted at all).

The regulatory treatment of the form of regulation in the context of beta therefore remains very unclear. The regulatory decisions listed in the table above include both

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43 The Allen Consulting Group (2006), Advice in Relation to SFG Report on Rate of Return for Gas Distribution, Memorandum to ESCOSA, p.3.

44 Queensland Competition Authority (2006), Final Decision: Revised Access Arrangements for Gas Distribution Networks – Envestra, p.104.

45 ACCC (2002), Final Decision: GasNet Australia Access Arrangement Revisions for the Principal Transmission System, p.111.

price cap and revenue cap regulation (as well as hybrid approaches), however there is no discernible difference between these alternatives in the recommended estimates.

In our view, as noted previously, residual exposure to volume risk provides further support for selecting a point estimate from the upper quartile of a range, over and above any such adjustments to reflect the asymmetric consequences of regulatory error.

4.4.6 Estimation of GasNet's beta: summary and conclusions

The estimation of beta is inherently imprecise and one of the most contentious aspects of regulatory decision-making. We have utilised three approaches to analyse a possible beta for GasNet, being:

- direct estimation;
- first principles analysis; and
- comparable companies (including examination of regulatory precedent).

We have concluded that the beta estimates arrived at via direct estimation cannot be relied upon given the difficulties caused by infrequent trading. Attempting to adjust for this via the application of the Scholes-Williams technique did not improve the performance of the estimate (in fact it was worse).

After filtering unsuitable companies from the sample, the comparable companies analysis was limited to overseas firms involved in gas distribution. Based on Blume-adjusted estimates, the average asset beta across this sample was 0.54 (equity beta of 1.33), with 69% of firms lying within one standard deviation of this estimate. This was close to the estimate for gas-only firms, which was 0.52 (equity beta of 1.28). The average for US firms only was somewhat lower at 0.46 (equity beta of 1.14). To the extent that asset betas tend to be mean-reverting through time, we believe that the Blume-adjusted measure provides a better indication of the long-term forward looking beta estimates for each sector.

Given potential differences across these jurisdictions, caution should be exercised in interpreting these results, as well as relying on overseas comparators, so these estimates will largely be used to provide context. At the same time, given there are a number of firms in the sample from different jurisdictions, these differences will also to some extent have 'averaged out'. What this does suggest is that the average equity beta implied by energy regulatory decisions in Australia, which is 1, cannot be considered high and possibly underestimates the true beta for a firm operating in the gas industry.

There is reasonably strong regulatory precedent for an equity beta of 1, which is also recommended by the AER's statement of regulatory principles for electricity transmission. The AEMC has made a similar recommendation in the revised National Electricity Rules published in November 2006.[46] While estimation issues raise questions regarding the reliance on point estimates, our analysis suggests that there is no reason why an equity beta of *at least* 1 should not be adopted for GasNet. Regulatory decisions have generally not drawn a distinction between gas and electricity (with the exception of the QCA, which views the risk profile of gas to be higher), nor have they distinguished between transmission and distribution. As noted above, they have also not distinguished between the form of regulation.

The comparable companies analysis suggests that the actual beta could be higher than this. We do not believe there is any evidence to support a value of less than 1 and in fact in our view if such a value was selected it would significantly increase the probability of regulatory error.

We are of the view that an estimate between 1 and 1.2 is reasonable (with the upper bound based on the estimates observed from the comparable companies analysis). This is equivalent to an asset beta of between 0.4 and 0.49 based on assumed capital structure of 60%.

While we believe that:

- GasNet's residual exposure to systematic risk; and
- the asymmetric consequences of regulatory error,

would support the selection of a point estimate from the upper quartile of this range, the weight of regulatory precedent suggests that a value of 1 is most likely to be adopted by the AER (particularly given this is contained in the AER's *Statement of Regulatory Principles*).

4.5 Market risk premium

A detailed analysis of the market risk premium (MRP) is contained in Appendix C. This provides an overview of the recent literature relating to the MRP, as well as the results of our own analysis.

The MRP is the amount an investor expects to earn from a diversified portfolio of investments (reflecting the market as a whole) that is above the return earned on a risk-

46 AEMC (2006), National Electricity Rules Version 11.

free investment. The key difficulty in estimating the MRP arises from it being an expectation and therefore it is not directly observable.

Estimates of the MRP have typically relied on estimating a plausible range for the MRP using historical data, and then choosing a point (or constrained range) within this range. The generally accepted range for the MRP among corporate finance professionals in Australia has been 6% to 8%. This range is largely favoured because of empirical evidence of the long-term historical, realised MRP in Australia.

There is considerable uncertainty surrounding the estimation of the MRP and it can be particularly volatile in the short-term. Caution should therefore be exercised in attributing trends based on estimates produced over short horizons. Our analysis has concluded that a horizon of at least forty years is required to produce a meaningful estimate.

A number of commentators have argued that the value of the MRP is falling, however to date, no evidence has been produced to demonstrate the impact of these influences on investors' risk and return expectations, or the potential quantum of such an impact on the MRP. To the extent that some of these arguments have emanated from recent observations of the MRP that have been estimated over a relatively short time period, the evident volatility of the short-term MRP means that considerable caution should be exercised before any conclusions are drawn based on these recent estimates. Further, given this short-term volatility, studies over longer horizons will be needed before any conclusions can be drawn regarding the possible permanency of changes in the MRP.

In regulatory decisions regulators have consistently adopted a value for MRP of 6%. The fact that economic regulators have tended to adopt relatively low estimates of the MRP is a matter of some policy concern given the asymmetric consequences of regulatory error outlined above.[47]

The long-term average estimate of approximately 7% well exceeds the regulatory precedent of 6%. While there is some debate surrounding the possibility that the value of the MRP has fallen, there is no evidence to demonstrate the impact that this may have had on the MRP. Adopting a value below 7% is essentially already a concession to a possible reduction in the value of the MRP, notwithstanding the lack of evidence to quantify any impact. The assumption of 6% adopted by regulators should therefore still be regarded as the lower bound of a reasonable range. There is no basis to believe that this lower bound should be reduced further, and to do so could risk compounding regulatory error.

47 Productivity Commission (2002), *Review of the National Access Regime*, PC Inquiry Report.

We believe that a range of between 6% and 7% is reasonable.

4.6 Cost of debt

The cost of debt capital is normally calculated as the risk-free rate plus a margin for credit or default risk. Debt issuance costs are generally also incurred and these are either reflected in the cost of debt (as an addition to the debt margin) or the cashflows (in this regard, we note that the AER intends to treat debt and equity raising costs as opex items)[48]. These are to be considered separately so have not been addressed here.

4.6.1 Debt margin

The typical approach to determining the debt margin involves:

- if the firm is unrated, assuming an appropriate 'notional' credit rating, which reflects the risk of default; and
- determining an appropriate margin based on the difference between the current cost of debt for a firm of that credit rating, and the risk-free rate. This should be estimated over the same time period as the risk-free rate.

A common starting point for the notional credit rating assumption is BBB, or minimum investment grade. In regulatory decisions, assumptions between BBB and A have tended to be adopted (the ACCC has adopted a rating of A as the benchmark for transmission network service providers).

We note that the ACCC's 2002 decision with respect to GasNet was BBB+. This was determined as an 'average' of the credit ratings of four firms, being:

- GasNet (BBB);
- Envestra (BBB);
- Alinta (BBB); and
- AGL (A).

It could be argued that an appropriate 'average' of these firms at the time was BBB rather than BBB+, particularly given the asymmetric consequences of regulatory error.

GasNet's current rating is BBB. Current ratings of other Australian gas businesses, as well as the five year average capital structure maintained by each firm, are summarised

48 Australian Energy Regulator (2005), op.cit., p.21.

in the following table (it should be noted that the ratings agency will be putting more weight on current and projected debt levels, rather than historical levels).

Table 9 Current credit ratings: gas (Australia)

Firm	Rating
Envestra	BBB-
Alinta	BBB (negative outlook)
AGL	BBB

Source: Bloomberg

It is also noted that the DBNGP Trust has a rating of BBB-. The AEMC's new National Electricity Rules propose an assumption of BBB+ for electricity transmission.

A rating of BBB+ is considered too high, with a rating of BBB considered more appropriate, particularly with a gearing assumption of 60%. A rating of BBB was also assumed by ESCOSA in its most recent decision in relation to Envestra. Given that the gas industry is fundamentally riskier than electricity transmission, a rating of less than the BBB+ benchmark adopted by the AEMC is considered appropriate, particularly if both industries are to adopt the same gearing levels.

We have therefore assumed a rating of BBB for the purpose of this analysis, noting that it is possible that ratings may be trending even further downwards in the industry.

Based on this assumption, we have taken the difference between the forty day average of the ten year Commonwealth Government bond and the benchmark cost of ten year BBB-rated debt, for the period ending 26 February 2007 (sourcing data from Bloomberg). The resulting spread was 114 basis points, resulting in a cost of debt of 6.99%. As highlighted above, this is before any allowance for debt raising costs.

4.7 Gamma

A detailed analysis of the issues associated with the estimation of gamma, including a review of the literature and the results of a simple diagnostic we have undertaken, is provided in Appendix D.

Determining an appropriate value for gamma has proven reasonably contentious. Regulators are now consistently adopting a value of 0.5. The analysis in Appendix D supports our conclusion that while gamma may previously have had some value to investors, this value may now be zero, particularly following the introduction of the 45 day rule that has essentially precluded foreign investors (who are the marginal price-setting investors) from deriving any benefit from franking credits. The following section summarises this analysis.

4.7.1 What is gamma

The cost of capital is traditionally calculated on an after-corporate tax basis. With dividend imputation, corporate tax paid prior to the distribution of dividends can be credited against the tax payable on the dividends at a shareholder level.

In other words, corporate tax is a prepayment of personal tax withheld at a company level. Gamma (γ) is the proportion of the corporate tax which can be claimed as a tax credit against personal tax, that is, it is the value of personal tax credits. Once this value has been determined, then either the WACC or the cash flows to which WACC is applied is adjusted to reflect the value of the tax credit to investors.

Gamma is the product of two inputs which must be estimated:

- the proportion of tax paid that has been distributed to shareholders as franking credits (the distribution rate); and
- the value the marginal investor places on $1 of franking credits, referred to as the value of franking credits.

While the distribution rate can be generally observed from taxation statistics, the value of franking credits cannot be directly observed. The value of franking credits is determined at the level of the investor and is influenced by the investor's tax circumstances. The value of gamma is between zero (no value from franking credits) and one (full value of franking credits).

4.7.2 Valuation of gamma

The issue of the value of franking credits is normally linked to the identity of the marginal investor in Australia (in other words, the investor that contributes the last dollar of capital to the firm, and hence sets the cost of capital). In identifying that marginal investor, it is appropriate to consider the shareholder profile of an 'efficient benchmark' firm, which is consistent with the approach taken to determine other WACC parameters.

In open capital markets such as Australia, which have large capital requirements but an insufficient internal capital source, external capital must be drawn upon. In the context of imputation credits this means that both foreign and domestic investors will hold shares in Australian companies. It is reasonable to assume that the marginal investor will be a foreign investor, that is, they are most likely to contribute the last dollar of capital to the firm and hence set the market-clearing price that determines the cost of capital. Further, for the reasons outlined in section 3.3.1 above, it remains appropriate to assume this in a domestic CAPM framework. That is, recognition of the practical influence of foreign investors in the Australian market does not required that the CAPM should be specified based on an international version.

Foreign investors cannot directly take advantage of dividend imputation. Prior to changes to the Australian taxation law in 1999, these investors could indirectly benefit by selling their shares (with the dividend and franking credit entitlements attached) to domestic investors. These domestic investors could then offset these credits against their personal tax liabilities. The foreign investors would then repurchase the shares once it has gone 'ex dividend'.

Since the introduction of the 45-day rule, this trading can no longer occur. Hence, foreign investors can no longer derive an indirect benefit from franking credits, with the benefit now only accruing to resident Australian shareholders. As a consequence, while franking credits may have had some value to the marginal investor prior to the introduction of the 45-day rule, the loss of this benefit will now be reflected in a low estimated gamma, perhaps even zero.

Empirical analysis supports the view that the value of gamma has now fallen (refer Appendix D). For example, Cannavan, Finn and Gray find that if attention is focused on large companies that have substantial foreign investment, the value of the franking credits since the restriction in trading of franking credits was imposed, is near zero.[49]

While a number of studies have still estimated a value for gamma (although there is considerable variation in these estimates), key concerns are that:

- studies using the dividend drop-off methodology need to be treated with extreme caution given the collinearity between dividends and franking credits; and
- the introduction of the 45-day rule resulted in a major structural change that has fundamentally impacted the value of franking credits. Any studies that seek to estimate gamma using data prior to this date will over-estimate the value of gamma.

We have also conducted our own tests to determine whether gamma potentially has a value other than zero. As an extension to this model, we tested whether or not franking credits were valued by the market at 50%, 70% and 100% of their face value, which was emphatically rejected. All in all, there is insufficient evidence to reject the theoretical hypothesis that franking credits are worthless to the marginal investor. Fundamentally, the implication of these findings is that gamma should be set to zero.

49 D. Cannavan, F. Finn and S. Gray, (2004). "The Valuation of Dividend Imputation Tax Credits in Australia" Journal of Financial Economics, 73, 167-197.

On the basis of this evidence we believe that it is appropriate to assume a value of zero for gamma. This includes:

- evident difficulties in estimating a reliable value for gamma (which may be because it has no value);
- a strong theoretical foundation, being that since the introduction of the 45-day rule, franking credits are now of no value to the marginal foreign investor (whereas they may have had some value prior to this); and
- empirical evidence to support a value of zero, both from the recent literature and our own analysis which confirmed that we cannot conclude that gamma has a value other than zero.

We believe there is now sufficient evidence emerging to prompt a review of this precedent by regulators, with the preferred gamma value now likely to be zero.

4.8 Inflation

There are a number of alternative approaches to estimating inflation.

The first is to reference current market forecasts, such the Reserve Bank's *Statement on Monetary Policy*, which surveys market economists for their outlook for inflation over the medium term. One of the main difficulties in relying on this approach is that this reflects a short to medium term outlook for inflation. Under the CAPM framework, parameters are specified based on long-term investor expectations.

The second alternative is to assume that given the objective of monetary policy is to maintain inflation within a 2 to 3% band, it is appropriate to assume say, the mid-point of 2.5% as the long-term expected outlook for inflation. The key risk with this approach is that actual inflation could be sustained at higher (or lower) levels for an extended period of time. In view of the asymmetric consequences of regulatory error, selecting an estimate from the upper bound of this range (ie 2.5% to 3%) may therefore be more appropriate.

Third, the estimate for expected inflation can be derived from the difference between the yields on the ten-year Commonwealth Government nominal and indexed bonds, based on the Fisher equation.[50] This is the most commonly applied technique in regulatory determinations. It is estimated by averaging the indexed bond yield over the same horizon as the risk-free rate, and then calculating implied inflation using the Fisher equation.

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50 Inflation = {(1+nominal rate)/(1+indexed bond rate)}-1

One of the potential risks with this approach is that the indexed bond market in Australia is generally not as liquid, particularly when compared to the liquidity of ten-year Commonwealth Government bonds, although this can vary in the short-term depending on demand drivers. If turnover is lower, the current indexed bond yields will not necessarily fully reflect the market's current expectations for inflation. The exception to this has been more recent times, where there has been increased demand for indexed bonds by institutional investors. However, according to the Reserve Bank:[51]

> As a consequence, yields on inflation-indexed bonds have been a little lower than they may have otherwise been, making it difficult to use them to draw conclusions about inflation expectations.

There are potential risks with any estimate that is being used to measure investors' current expectations over the longer-term, particularly where those estimates are vulnerable to short-term financial market influences. This is to some extent (but not necessarily fully) dealt with by averaging rates over a short time period.

The risk of actual outcomes deviating from the forecast will remain irrespective of the point estimate chosen. The impact of this risk on the business depends on whether there is any ex-post adjustment for actual inflation at the end of, or during, the regulatory period. We have not sought to address the issue of which party bears inflation risk in this report.

Despite these shortcomings, the Fisher equation is consistent with the approach used to measure the risk-free rate and debt margin. While each method has its strengths and weaknesses, we have used this preferred method to derive a current estimate for expected inflation. Based on an indexed bond yield of 2.68% (averaged over the same period ending 26 February 2007[52]) and a risk-free rate of 5.85%, the implied expectation for inflation is 3.09%.

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[51] Reserve Bank of Australia (2007), Statement on Monetary Policy - February 2007, http://www.rba.gov.au/PublicationsAndResearch/StatementsOnMonetaryPolicy/Feb2007/domestic_financial_markets.html.

[52] The risk-free rate and corporate bond rate data were sourced from Bloomberg. The indexed bond yields were sourced from the Reserve Bank of Australia. As there is no ten year indexed bond rate published by the Reserve Bank, we derived this by interpolating between the 2015 and the 2020 maturities. It should also be noted that no indexed bond rates were published for the 26th of January 2007 (however, the risk-free rate data series sourced from Bloomberg did have a rate published on that day). We therefore averaged the indexed bond rate based on the same start and finish dates as the risk-free rate series, which means that we only have 39 observations for the indexed bond yield. A visual inspection of the risk-free rate data reveals that there was no 'aberration' on the 26th of January. We are therefore of the view that the absence of an indexed bond rate on this one day would not have had an impact on our overall estimates.

5 WACC Estimate

The resulting WACC estimate is provided in the following table.

Table 10 GasNet: WACC Estimate

Parameter	**Synergies' Recommended Range**
Nominal risk-free rate[a]	5.85%
Debt proportion	60%
Equity proportion	40%
Debt margin[b]	1.14%
Market risk premium	6% - 7%
Gamma	0
Debt beta	0
Equity beta	1-1.2
Asset beta[c]	0.4-0.49
Tax rate	30%
Inflation	3.09%
Cost of debt	**6.99%**
Cost of equity	**11.85% - 14.25%**
NOMINAL POST-TAX WACC	**8.93% - 9.89%**

a Based on a 40 day average for the period ending 26 February 2007.

c Based on a 40 day average for the period ending 26 February 2007, assuming a notional credit rating of BBB. **Does not include allowance for debt-raising costs.**

d Based on the Monkhouse formula.

A Comparable companies

Table A.1 Comparable Companies

Company	Raw asset beta, Blume-adjusted asset beta[a]	Average Debt to value[b]	R^2	Standard error	t statistic
Distrib De Gas Cuyana SA-B (Argentina) Located in Argentina, the company's main activity is distributing natural gas, either through its own account or on behalf of third parties.	1.04, 0.99	10%	0.21	0.32	3.6
Cia de Gas de Sao Paulo-PR A (Brazil) The company is involved in gas distribution in the Brazilian state of Sao Paulo. The company supplies natural gas to industrial, residential and commercial customers.	0.65, 0.67	30%	0.39	0.15	6.2
Cia de Cons de Gas de Santia (Brazil) *{to be completed}*	0.56, 0.57	40%	0.28	0.18	5.1
Gaz Metro LP (Canada) Gaz Metro distributes 97% of the natural gas used in Quebec. Other interests include two natural gas transmission companies, and selling goods and services related to other aspects of energy, fibre-optics and underground utilities.	0.41, 0.47	40%	0.16	0.15	4.5
Shizuoka Gas Co Ltd (Japan) Shizuoka distributes gas for domestic, commercial and industrial use in Japan.	0.41, 0.44	50%	0.13	0.25	3.2
Seoul City Gas Co Ltd (Japan) The company is interested in the distribution, import and supply of natural gas for residential, commercial and industrial use.	0.29, 0.34	56%	0.1	0.18	3.6
Enagas (Spain) Enagas is involved in reception, storage, transport and distribution of natural gas in Spain. Enagas supplies domestic, commercial and industrial users. The group also owns gas pipelines	0.39, 0.5	30%	0.13	0.13	4.3

Company	Raw asset beta, Blume-adjusted asset beta[a]	Average Debt to value[b]	R^2	Standard error	t statistic
and is involved in regasification and storage of natural gas.					
Azienda Mediterran Gas Acqua (Italy) The group's principal activity is to provide public services distribution of natural gas, water, heating (gas) and electricity. Other activities include technological support, technical and organisational assistance, skill building and knowledge sharing programmes, telecommunications and research and development programs for the application of new technologies.	0.7, 0.72	25%	0.38	0.15	6.2
Gail India Ltd (India) The group's primary activities relate to LPG and natural gas distribution and processing petrochemicals. Other interests relate to telecommunications and power.	0.96, 0.93	14%	0.46	0.17	6.5
Saibu Gas Co Ltd (Japan) The business of Saibu relates to gas sale and distribution, heating services, selling LNG and using LNG cryogenic energy and construction, installation and repair of gas equipment. Saibu services 16 cities and 16 towns in Japan.	0.21, 0.28	60%	0.17	0.09	5.9
Otaki Gas Co Ltd (Japan) The primary activities of Otaki relate to supply and sale of natural gas, LPG and associated business of gas appliances. Other activities relate to business automation products and data processing. Otaki operates in Japan.	0.41, 0.48	40%	0.19	0.14	4.9
Hokuriku Gas Co Ltd (Japan) The company supplies gas and gas related appliances to households, businesses and industry in the Niigata region of Japan. Wholesale LPG, gas related engineering and equipment are other interests.	0.48, 0.57	25%	0.11	0.18	3.6
Gas Natural Ban SA-B (Argentina) Based in Buenos Aires, the company is involved in the distribution and transmission of natural gas. It supplies the residential and commercial markets. Other activities involve installations, air conditioning, central and gas water heating, heating systems and compressed natural gas.	0.38, 0.42	50%	0.25	0.14	5.4
Centrica PLC (UK) Centrica operates in Britain, Europe, the United States and Canada. Other than gas distribution, the group is involved in gas storage, electricity, drain cleaning, electricity generation, residential customer service.	0.85, 0.85	15%	0.33	0.19	5.3
Gas Natural SDG SA (Spain) Gas Natural supplies customers in Italy, Spain and Latin America. In addition to gas distribution,	0.56, 0.62	25%	0.29	0.13	5.7

Company	Raw asset beta, Blume-adjusted asset beta[a]	Average Debt to value[b]	R^2	Standard error	t statistic
Gas Natural also has electricity supply operations.					
Southern Union Co (US)	0.54, 0.51	55%	0.38	0.21	5.6
The company is involved in transportation, distribution and storage of natural gas in the United States. The company is also involved in LNG terminalling and regasification. The company distributes natural gas to residential, commercial and industrial customers.					
Sempra Energy (US)	0.6, 0.62	35%	0.32	0.17	5.4
Sempra has interests in electricity and gas services and distribution and owns and operates infrastructure assets power plants, natural gas pipelines and LNG receipt terminals. Sempra also provides risk management services to customers to minimise their energy costs.					
Vectren Corporation (US)	0.38, 0.44	45%	0.21	0.13	5.2
Vectren provides electricity and gas services and energy audits to domestic consumers. Other energy related products are sold to businesses, such as uninterruptible power supplies and surge protection. A service is also provided that locates utility lines on property.					
Atmos Energy Corp (US)	0.34, 0.41	45%	0.18	0.12	5.2
Atmos Energy delivers natural gas to residential, commercial and industrial consumers. Atmos also markets natural gas to industrial users, provides gas transportation, provides management services and own and manage gas storage and pipeline assets.					
Nisource Inc (US)	0.38, 0.40	55%	0.25	0.17	4.9
The Nisource group is involved in all aspects of the gas supply chain including exploration, production, transmission, storage and distribution. They are also involved in electricity generation, transmission and distribution.					
Keyspan Corp (US)	0.34, 0.40	50%	0.2	0.14	4.9
Keyspan operates through its Gas Distribution, Electric Services, Energy Services and Energy Investments divisions. The Gas Distribution division distributes natural gas to consumers. The Electric Services division manages generation, transmission and distribution electricity services for utility services. Energy Services provides varied service and maintenance roles and Energy Investment includes gas exploration and pipelines, storage facilities and LNG facilities.					
AGL Resources Inc (US)	0.32, 0.40	45%	0.14	0.12	4.8
AGL Resources is involved in gas distribution and wholesale services, and have interests in energy investments including gas pipelines and LNG facilities.					
Laclede Group Inc (US)	0.4, 0.47	40%	0.17	0.14	4.7
The primary interest of the Laclede group is natural gas distribution. The Laclede group also owns a cable locating and marking company.					

Company	Raw asset beta, Blume-adjusted asset beta[a]	Average Debt to value[b]	R^2	Standard error	t statistic
Peoples Energy Corp (US)	0.39, 0.46	40%	0.12	0.17	3.8
Peoples Energy has interests in gas distribution, power generation (natural gas fired power plants), oil and gas production and energy marketing. The core business of Peoples Energy is natural gas distribution.					
Nicor Inc (US)	0.6, 0.62	35%	0.18	0.25	3.7
Nicor Gas is a gas distribution company that operates a network of pipelines and storage facilities. Nicor Inc also has a containerised shipping business and has interests in other unregulated energy-related businesses.					
Semco Energy Inc (US)	0.4, 0.37	70%	0.15	0.46	2.9
Semco is a gas distribution company in Michigan (Semco Energy Gas Company) and Alaska (Enstar Natural Gas Company). Semco Energy is also involved in propane distribution, interstate pipelines and gas storage in the United States (Semco Energy Ventures).					

a Based on Blume-adjusted equity betas. Delevered using Monkhouse approach.

b Average over past five years

Source: Bloomberg

B Estimation Error in Beta Assessment

It is not possible to directly observe a firm's true beta[53]. Instead, estimates are obtained by regressing the historical returns of a firm's shares against the historical returns for a market index, over the same time period. It is possible that there is considerable 'noise' in both data series, which can result in measurement error. This is particularly likely in the data history for the individual firm. As a consequence, the resulting data estimates can be of limited reliability and caution should be exercised in applying these estimates in a forward-looking analysis.

In addition, as noted above, historical data is being used to proxy expected values. To the extent that the underlying risk profile of either data series is likely to change in the future (that is, either the risk profile of the firm and/or the 'average' risk profile of the market as a whole), this will reduce the reliability of these historical values as forward looking estimates. This is an issue that needs to be considered in both direct estimation and comparable companies analysis.

Thin trading

A common source of error is thin trading. Given GasNet's shares were relatively thinly traded, this will be an issue that needs to be dealt with here. Asset pricing models generally assume that shares trade continuously, which means that a current price can be obtained at any time. However, this is often not the case for individual shares. As a consequence, one may be regressing a data series consisting of relatively infrequent observations against a market index comprising more actively traded shares.

If a share is traded relatively infrequently, its pattern of returns is likely to be more smoothed and hence it may have a deceptively lower variance. This in turn can mean that its covariance with the market, and hence its beta estimate, can be understated. This problem is more serious the shorter the measurement period (that is, a beta estimated using daily returns will have more significant measurement errors than an estimate based on monthly returns). This is also why longer estimation periods are generally favoured, such as five years of monthly data. The risk of going too far back in time, however, is that the firm's business, and hence its risk profile, has changed over time.

53 The 'true' beta refers to the long-term underlying value.

One procedure used to adjust for thin trading is the Scholes-Williams technique (this is used by the Australian Graduate School of Management in constructing its CRIF database of beta estimates for Australian firms). This recognises that for thinly traded shares, their returns may be related to the return on the market for more than one period. Hence, this technique includes one lead and one lag observation for the return on the market in the regression equation and adjusts for autocorrelation (if it exists). However, the Scholes-Williams betas reported in the CRIF database, for example, are consistently higher and have a much larger standard error.

A similar method is the Dimson adjustment. Like the Scholes-Williams technique, it includes leads and lags however does not stipulate the number that can be used. It also does not adjust for autocorrelation.

Other sources of estimation error

It is also believed that betas are mean reverting. In other words, over time, the betas of all firms will gradually move towards the equity beta of the market, which is 1.[54] This means that future estimates of beta are likely to be closer to one than current estimates.

There are a number of other sources of estimation error, including:

- *sensitivity to the return interval* (that is, daily, weekly or monthly): different estimates can be produced using different intervals over the same time period;
- *outliers*: the influence of large outliers, which may be one-off events, can confuse the relationship between the returns of the firm and the market (and can violate the CAPM assumption that returns are normally distributed); and
- *misspecification of the market portfolio*: as noted previously, the market portfolio underpinning CAPM is intended to comprise all risky investments that are available in the market. As there are obvious practical difficulties in constructing this portfolio and estimating its returns, the estimation of returns on an appropriate sharemarket index is generally accepted to be a suitable proxy. Given the return profile of the sharemarket index is likely to vary from the return profile of the 'true' market portfolio, a further source of estimation error is introduced.

[54] There are a number of reasons hypothesised for this. First, it is argued that firms are more likely to grow via diversification, rather than expansion in the same line of business. Second, through time, managers will consciously seek to manage the risk of the firm around the 'average' risk of the market, and implement strategies accordingly.

Addressing measurement error

There are a number of ways to address measurement error. As a starting point, any beta estimates with poor statistical properties should be discarded (such as a very low R^2 or a high standard error).[55] There are a number of other ways to deal with the uncertainty surrounding the estimation of beta, including:

- adjusting for lagged effects that may arise where shares are thinly traded, as discussed above;
- adjusting for mean reversion using the Blume adjustment[56];
- the formation of portfolios. Portfolio betas have substantially lower standard errors and yield more econometrically sensible estimations. While there are benefits in using this approach via reductions in the standard error, as more firms are used caution should still be exercised to ensure that they are relevant comparators.

A recent report by Gray et al provides a useful summary of the various methods of estimating beta, as well as their performance.[57] The study uses historical data to compare the predicted beta estimate in accordance with CAPM, with the actual equity return for the relevant forecast period. The closer the predicted estimate to the actual equity return, the better the estimation technique. A summary of the findings of the report are:

- it is preferable to use data periods of longer than four years;
- monthly observations are preferred to weekly observations;
- Blume-adjusted estimates that account for mean reversion provide better estimates;

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55 The $\mathbf{R^2}$, or coefficient of determination, measures the explanatory power of the regression equation (that is, how much of the variability in Y can be explained by X). It takes a value of between 0 and one. For example, an R-squared of 0.7 would suggest that 70% of the variability in the individual share's returns is explained by variability in the returns on the market. The more 'noise' in the data, the less it pertains to the underlying relationship and hence the lower the R^2. The **standard error** measures the sampling variability or precision of an estimate. That is, as the estimate is derived from a sample distribution, it measures the precision of the model parameter. A lower standard error is preferred as it indicates a more precise measure. A third commonly used measure is the **t statistic**. The t statistic is calculated for each coefficient in a regression model (in this case, the beta coefficient) for the purposes of hypothesis testing. The tendency is to test the hypothesis that the regression coefficient is significantly different from zero. This is done within a specified confidence interval (for example, 95%). Generally, the t statistic should exceed two to be considered reliable. These measures have been used in this analysis to screen comparator beta estimates.

56 The impact of this adjustment is to 'draw' the value of the estimated beta closer to one. The typical adjustment is simply: Adjusted beta = (1/3 * the market beta of one) + (2/3 * estimated beta). This can be reduced to: Adjusted beta = 0.33 + (0.67 * estimated beta).

57 S. Gray, J. Hall, R. Bowman, T. Brailsford, R. Faff, R.Officer (2005), The Performance of Alternative Techniques for Estimating Equity Betas of Australian Firms, Report Prepared for the Energy Networks Association.

- statistical techniques that eliminate outliers are preferred, provided the outlier is not expected to re-occur; and
- a beta estimate derived from a sample of firms in an industry is preferred to an estimate for an individual firm.

A further interesting finding was that assuming an equity beta of one for a firm generally outperformed standard regression estimates, and that this may be a more appropriate assumption for beta if data cannot be obtained over a suitably long time period.

C Market risk premium

C.1 Background

Investors are faced with a spectrum of investment choices, ranging from virtually risk-free government securities to extremely risky investments in speculative venture capital projects. Being risk-averse, investors will demand a higher price or risk premium for making investments in increasingly risky assets. As noted above, under the CAPM framework, the rate of return only compensates investors for bearing systematic or non-diversifiable risk.

The premium that investors holding a portfolio or risky assets can expect to receive over and above the return on the risk-free rate is represented by the market risk premium (MRP). It is the difference between the expected return on holding the market portfolio and the risk-free rate. As a forward-looking expectation it is difficult to estimate but generally, it is proxied by the actual average excess returns from holding shares (as measured by the All Ordinaries or S&P200 Accumulation Index) compared to long-dated government bonds.

Under the CAPM, the MRP estimate should be forward-looking and correspond to the time frame of the asset under analysis, which tends to be long-term. As it cannot be observed directly, a number of studies have sought to estimate the historical MRP. Results have tended to fall within a range of 6 to 8%, although they are sensitive to the assumptions made, particularly in terms of the time period over which it is measured. Estimating the MRP is therefore one of the key areas of WACC estimation that is characterised by considerable uncertainty, which makes the specification of a point estimate within a range extremely difficult.

With some commentators arguing that the value of the MRP has fallen in recent times, there has been pressure to choose an estimate from the lower end of this range. Historically, regulators have consistently adopted a value of 6% and movements to an even lower value have been mooted.

The following discussion will highlight the considerable uncertainty surrounding the estimation of the MRP. Studies that have estimated the MRP by measuring the average historical premium over a long time horizon have yielded estimates in excess of 7%. While arguments have been made that the value of the MRP has fallen, no adequate empirical evidence has been produced to quantify any impact and in the absence of such data, long-term historical averages remain the most appropriate measure.

Shorter-term averages can be highly volatile and hence a horizon of at least 40 years is recommended.

This section will provide:

- estimates based on two commonly used approaches, being survey data and historical averaging;
- an analysis of the empirical issues associated with historical averaging, which primarily focuses on the selection of the averaging period; and
- conclusions and implications for the MRP.

C.2 Overview of the literature on MRP estimation

Two of the most commonly used methods commonly to estimate the MRP are:

- survey evidence; and
- historical averaging.[58]

C.2.1 Survey data

Survey methods poll informed commentators (such as portfolio managers and academics) to assess expectations of the future risk premium. On face value, surveys have a substantial advantage over historical estimates of the MRP because they are forward-looking. Properly constructed, they should provide actual forward-looking opinions.

However, there are a number of key limitations, including:

- they are likely to be more heavily influenced by recent events;
- they tend to reflect short-term expectations;
- estimates are based largely on opinion, which may not necessarily be founded on sound fundamentals; and
- some respondents may have incentives to produce certain outcomes, which can lead to biased results.

[58] Other methods that have been proposed include: (1) Merton's model, where market risk premium is based on its proportionality with market volatility; and (2) the dividend growth model. Neither of these approaches are commonly applied in practice.

There is no reason to believe that surveys are any more efficient in estimating the MRP than historical averaging. Of most concern is the fact that the studies can produce estimates of the MRP that contradict economic and financial theory.

While acknowledging the conceptual correctness of a forward-looking method to estimate MRP, we are not of the view that survey results should be used to derive estimates of MRP.

C.2.2 Historical Averaging

Historical averaging has been the most popularly employed method for estimating the MRP. Historical averaging involves observing the measured difference between the risk-free rate (based on the return on government bonds) and the return on the market portfolio[59] (based on the return on the share market index) over a period of time and averaging the rate. While data is readily available for this method it does rely on the assumption that the past is the best indicator of future risk and return expectations.

Methodological Issues

There are a number of issues of contention regarding historical averaging. The first is the time horizon over which the historical data should be analysed. One school of thought proposes that as long a horizon as possible should be used. This assumes that investors' risk premiums have not changed over time and the average market risk premium has remained stable.

An alternative view is that only more recent data is relevant, particularly if the market has undergone significant structural change over time (for example, the introduction of dividend imputation), which in turn have influenced how investors assess risk and return.

This approach results in an estimation problem in that estimates based on more recent data have standard errors that are too high to produce a statistically meaningful estimate. Further, conditions prevailing over a short period of time may not necessarily be an appropriate basis for a long-term forecast (for example, unusually high returns or high volatility). We examine this issue further below.

A second issue is the averaging method - arithmetic or geometric. Arithmetic averages are more popular but arguments are made in the literature for geometric averages on the basis that are more efficient (that is, they will produce less biased estimates of the

59 In the case of the return of the market, it represents the universe of investments available in the marketplace.

"true average"). This was supported by Gray and Officer.[60] They state that the arithmetic mean is the preferred method on the basis that we are looking to estimate the expected value of the MRP. They note that a geometric mean is appropriate:[61]

> …when estimating the aggregated return from a buy and hold strategy over a long period, but that is not the purpose here. The MRP is to be used in the CAPM to compute the cost of equity expressed in annual terms. Therefore, we require an estimate of the expected return, over the next year, on the market portfolio over and above the risk-free rate. What return do we expect on the market portfolio over the next year, relative to the risk-free rate? The historical data provides us with many observations on what the market returned relative to the risk-free rate over a one-year period. To the extent that each of these observations should be given equal weight, a simple arithmetic average is appropriate.

We are of the view that an arithmetic average is the most appropriate method for estimating the MRP based on historical data. The CAPM is a single time horizon model and as such the use of a geometric average would be inconsistent with its assumptions.

Estimates from Selected Australian Studies

Estimates from several Australia studies are listed in Table C.1.

Table C.1 Selected Australian estimates of market risk premium

Author	Year	Period	MRP (%)
Officer	1985	1882-1987	7.9
Australian Graduate School of Management	1989	1974-1983	6.3
		1977-1983	11.7
Australian Graduate School of Management	1998	1964-1995 (incl Oct 1987)	6.2
		1964-1995 (excl Oct 1987)	8.1
Hathaway	1995	na	6.6
Davis	1998	na	4.5-7.0
Dimson et al	2002	1900-2000	7.5
Hancock	2005	1974-2003	4.5-5
Hathaway	2005	1875-2005	1 year arithmetic: 7
			10 year arithmetic: 7.2
Gray & Officer	2005	1975-2004	7.7
		1955-2004	6.43
		1930-2004	6.58
		1905-2004	7.15

[60] S. Gray & R. Officer (2005), A Review of the Market Risk Premium and Commentary on Two Recent Papers, A Report Prepared for the Energy Networks Association.

[61] ibid.

		1885-2004	7.17
Brailsford, Handley and Maheswaran (arithmetic mean, relative to bonds)	2006	1883-2005	6.2%
		1883-1957	6.1%
		1883-1987	6.4%
		1900-2000	6.2%
		1937-2005	5.8%
		1958-2005	6.3%
		1980-2005	6.0%
		1988-2005	5.1%

Sources: QCA (2000), Draft decision on QR's Draft Undertaking, Working Paper Number 4; Lally, M. (2004), Estimating the Cost of Capital for Regulated Firms; S. Gray & R. Officer (2005), A Review of the Market Risk Premium and Commentary on Two Recent Papers, A Report Prepared for the Energy Networks Association; J. Hancock (2005), The Market Risk Premium for Australian Regulatory Decisions, The South Australian Centre for Economic Studies; T. Brailsford, J. Handley & K. Maheswaran (2006), A Re-examination of the Historical Equity Risk Premium in Australia, unpublished working paper, p.28.

Recognising the problems inherent in individual estimates, it is common practice to refer to a range for MRP of between 6% and 8%, with the longest horizon studies, with the exception of Brailsford et al, estimating the MRP at above 7%.[62]

Three recent studies were published by Hancock[63], Hathaway[64] and Gray and Officer[65] in 2005. Gray and Officer's paper is largely a critique of the first two papers, although they have also produced their own estimates of the MRP. All studies produced estimates in excess of 6% for long-term historical averages. However, Hancock and Hathaway's recommended estimates are below 6% based on a number of 'ad hoc' adjustments made to the data.

Both authors produced estimates over long time periods however recommend that the time frame for estimation should be limited to the last thirty years. Ad hoc adjustments were made based on key events or trends, such as the increase in the price-earnings ratio (Hathaway) and the introduction of dividend imputation (Hancock). These adjustments were rejected in Gray and Officer's critique:[66]

> Both authors argue that events that are unanticipated and unlikely to repeat should be removed from the data set or the subject of adjustments to the historical data. Our response is that there are many events that are both unexpected and unlikely to repeat, and yet are not the subject of adjustment in either paper. The terrorist attacks of 2001 and the Asian crisis of 1997 are some examples.

[62] For example see: M. Lally (2004), Estimating the Cost of Capital for Regulated Firms and QCA (2000), Draft decision on QR's Draft Undertaking, Working Paper Number 4.

[63] J. Hancock (2005), The Market Risk Premium for Australian Regulatory Decisions, The South Australian Centre for Economic Studies.

[64] N. Hathaway (2005), Australian Market Risk Premium, Capital Research Pty Ltd.

[65] S. Gray & R. Officer (2005), op.cit.

[66] ibid., p.3.

> There are many economic events that affect stock returns. To eliminate those that are claimed to be unexpected and non-recurring would be to leave a scant and practically useless data set. Indeed it is precisely because there are unexpected events that affect markets in different ways that there exists a MRP in the first place! Rather than selectively eliminate from the data events that are considered to be unexpected, the preferred approach is to analyse a longer data set that contains both positive and negative shocks. Moreover, in a regulatory setting, this would invite an avalanche of submissions on which events were expected and which were not.

Gray and Officer produce a range of estimates for the MRP based on different time periods, all of which are significantly above 6%. The highest estimate, 7.7%, was actually observed when the timeframe was limited to the last thirty years, which is the period over which many authors have sought to claim that the MRP has fallen. They conclude that:[67]

> Estimates below 6% can only be achieved by making selected adjustments to the historical data.

It is therefore possible that the true value of the MRP has been well above 6% and in fact much closer to 7%. What is clear is that there is considerable uncertainty surrounding the estimation of the MRP. We will now consider some of these estimation issues in more detail, with a particular focus on the selection of the most appropriate horizon for historical estimation.

C.3 Empirical issues in historical averaging: further analysis

As would be evident from the preceding discussion, much of the debate surrounding the estimation of the MRP relates to the most appropriate empirical methodology to apply. There is general agreement regarding what the MRP is and how it is calculated but debate persists regarding the period over which the MRP is estimated and consequently the value of the MRP.

Ex-ante the MRP is a constant. It is estimated based on historical data and used in a forward looking process like a valuation model. Ex-post, the MRP is a variable. In fact if it were not a variable but a constant there would be no risk and no risk premium. Given the stochastic (or largely random) nature of the MRP, debate will persist regarding the best estimate. Overall, the fundamental CAPM principle that should drive the choice of the assumption is the extent to which that assumption is a reasonable expectation of a long-term, forward looking value for the MRP.

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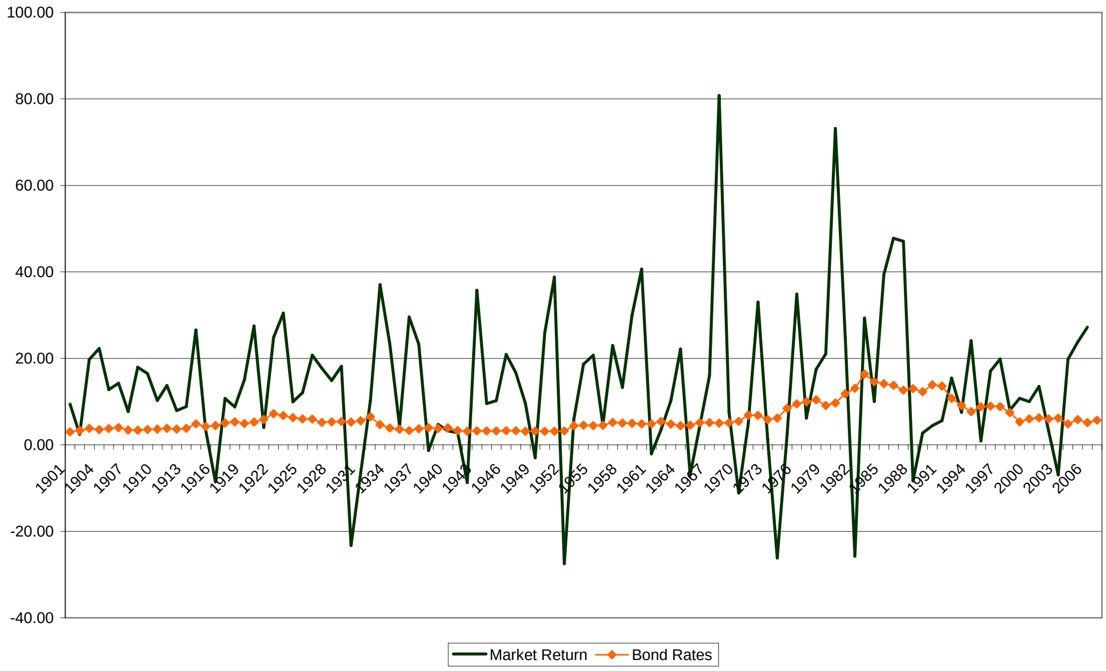
[67] ibid.

C.3.1 Calculation

As noted above, the common calculation of the MRP is as an arithmetic mean rate of return. It is simply the difference between the return earned in the market as evidenced by the percentage change in a broad accumulation index and the 10 year government bond rate at the start of the year. It is expressed as an annual percentage premium. Figure C.1 displays yearly changes in a broad market accumulation index and yearly 10 year government bond rates.

Figure C.1 Market Return and Government Bond Rates: 1900 to 2006

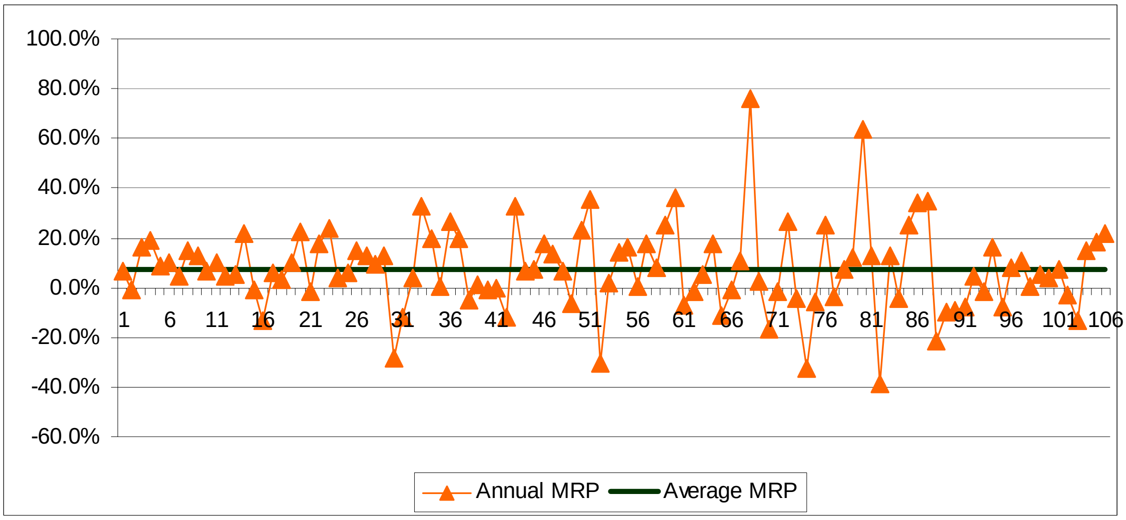


Data source: Bloomberg

It can be seen that over the 106 year period to 1 June 2006 bond rates are fairly constant compared to equity returns. Major movements in the MRP are therefore a consequence of movements in the equity market.

Using this data, the MRP has been calculated over the same 106 year period. Figure C.2 displays the annual MRP over this period relative to the long-term average of 7.6%, which is represented by the solid horizontal line.

Figure C.2 MRP over the Past 100 Years – Annual MRP Relative to Long-Term Average



Data source: Bloomberg

Table C.2 shows the value of the MRP when estimated over different averaging periods, all calculated over a period ending 31 May 2006. In other words, it shows the 'current' estimate for the MRP, depending on which horizon is chosen.

Table C.2 Value of MRP using Different Averaging Periods

Period of Averaging	Market Risk Premium
10	6.7%
20	3.7%
30	6.5%
40	6.8%
50	7.2%
60	7.3%
70	7.2%
80	7.2%
90	7.6%
100	7.5%
106	7.6%

Data source: Bloomberg

The longer-term results are consistent with other studies. The short-term results need to be interpreted with caution as the calculated answer depends heavily upon the number of observations and the start date for the period of calculation. All estimates are higher than 6%, with the exception of the 20-year average. The 20-year average is heavily influenced by a number of years of lower market returns in the late 1980s and 1990s (which subsequently increased, with the exception of 2002 and 2003) – as is evident in Figure C.2 above.

The contentious issue of the period over which the market risk premium is to be calculated is illustrated by Bob Officer's MRP analysis from 1882 to 1987.[68] It was found that the average market risk premium was 7.94% over the entire period. For each 10 year sub-period the premium ranged from 0.36% to 11.87% (interestingly, the two extremes were consecutive periods). This study illustrated that shorter-term premiums are highly volatile and the long run premium is close to 8%. Unlike long-term premiums, meaningful short-term premiums cannot be estimated and what is long-term is a question that needs to be answered.

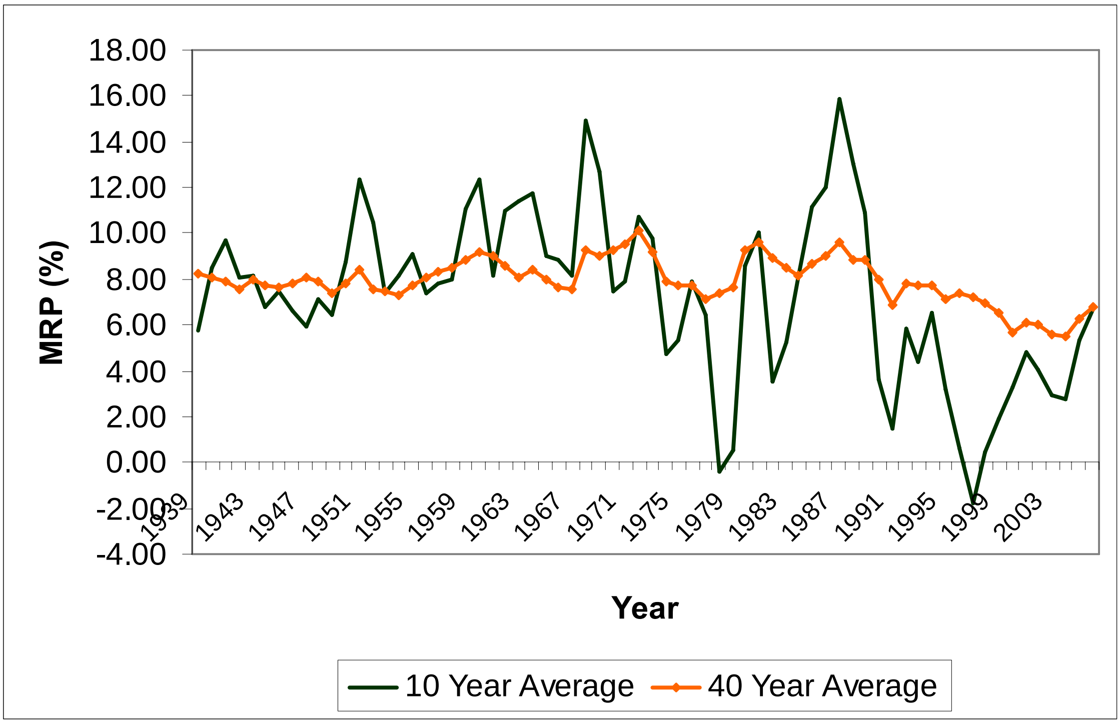
The volatility of short period calculations is most easily seen in the Figure C.3. This chart tracks a moving average calculated over horizons of 10 and 40 years[69]. The ten year average provides an indication of what the MRP has been over the short-term and hence is quite volatile (a number of the studies that have sought to provide support for a fall in the value of the MRP have also been estimated over short horizons). It shows an apparent 'dip' in the value of the MRP since around 1995, before reverting back towards the more stable 40-year average (as shown in Table C.2 above, in 2006 the 'current' value of the MRP based on the 10 year horizon was 6.7%, with the 40-year average producing a value of 6.8%).

This 'dip' may well explain why some more recent studies have proposed a lower value for the MRP. However, the key question is the extent to which these estimates are a reasonable proxy for a long-term forward looking expectation of the MRP, which is required under CAPM. The volatility of shorter-term estimates casts serious doubt on their reliability as such as proxy as future estimates of the MRP over this horizon could be well above, or below, the current estimate.

[68] B. Officer (1989), "Rates of Return to Shares, Bond Yields and Inflation Rates: An Historical Perspective", in Share Markets and Portfolio Theory, University of Queensland Press.

[69] The data has been collected since 1900, so the chart has been truncated at the date of the first 40 year average, which was in 1939.

Figure C.3 MRP: Moving Average over 10 and 40 years – 1939 to 2006



Data source: Bloomberg

Another way of examining the reliability of the estimates is to examine the standard error.[70] The standard error of the 40 year average is 0.15, and increases significantly to 1.08 for the 10 year average (the higher the standard error, the less reliable the estimate).The following figure shows the standard error for each of the averaging periods shown in Table C.2, ranging from 10 years through to 100 years (in increments of 10 years). This highlights the limited reliability of shorter-term estimates.

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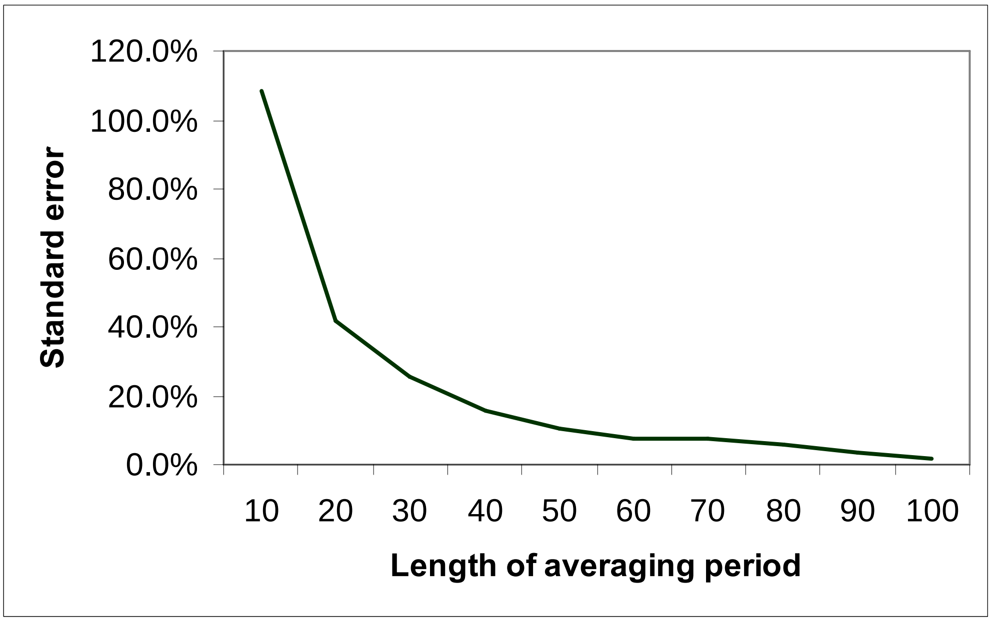
[70] This is calculated as the standard deviation divided by the number of observations (as the averages calculated are of the annual MRP,the number of observations is simply the length of the averaging period)..

Figure C.4 Standard error of MRP estimates produced over different averaging periods



Data source: Bloomberg

We can therefore conclude that empirically, an analysis over a period of less than 40 years will not result in a meaningful estimate. Gray and Officer conclude:

> A long period of data provides better statistical precision (the mean estimate has a lower standard error), but data from long ago may be less representative of current circumstances. It is generally agreed, however, that the minimum period required to provide sensible estimates is 30 years.[71]

From year to year, the MRP is extremely volatile and a longer-term average is required to produce a meaningful estimate. This casts considerable doubt over studies that are attempting to draw valid conclusions regarding the value of the MRP based on a shorter averaging period. While shorter-term studies may reflect the 'current' value of the MRP, the MRP's short-term volatility means that this estimate could well be higher, or lower, in the future. As a consequence, this short-term value cannot serve as a reliable proxy for the long-term, forward looking value of the MRP.

C.3.2 Structural change in the MRP

As noted above, it has been suggested that certain structural adjustments in the market may have resulted in a permanent reduction in the value of the market risk premium. For example, it has been proposed that the integration of Australia with world capital

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[71] S. Gray & R. Officer (2005), op.cit., p.21.

markets will reduce the variance of returns and therefore reduce the risk premium. Other factors include a reduction in the cost of acquiring the market portfolio, changes in risk aversion, changes in taxation regimes and reductions in market risk. Much of the literature that has examined this is in the area of market microstructure, however there have been no studies to quantify the possible impact on the MRP. For example, one Australian study estimated significantly different averages for two periods, 1877-1970 and 1971 to 2000, but was unable to show that the two estimates were statistically significant.[72] [73]

Some authors suggest that the market risk premium is statistically different for the period post-September 1987 compared to the period pre-September 1987. Davis estimated that the market risk premium may have fallen following the introduction of dividend imputation in recognition of the additional value of franking credits.[74]

We have sought to test the hypothesis that there is no difference between the premiums of the two sub-periods (in other words, this hypothesis would need to be rejected in order for there to be potential evidence that the MRP has fallen since the introduction of dividend imputation). This analysis produced a t-statistic of 0.92, which means that the hypothesis could not be rejected. This supports the contention that even though the premium is low after 1987, this change is not significant.

In a submission responding to ESCOSA's final decision in relation to gas distribution, SFG Consulting point out that under the CAPM, a reduction in the market risk premium will occur if there is either a reduction in the market's assessment of volatility or a reduction in the compensation investors' require to bear this volatility (or, a reduction on the Sharpe ratio).[75] They refer to recent estimates of the Sharpe ratio as calculated by Hathaway in 2005, which shows no difference in the value of this ratio for the period between 1882 and 2005 and the most recent ten years. They also respond to the Allen Consulting Group's proposition that the reduction in transaction costs has driven the reduction in the risk-reward trade-off (ACG cited evidence by Siegel which estimated a potential impact on the MPR of between 1 and 2%):[76]

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72 Unpublished study by Gray and Hall cited in M. Lally (2004) , op.cit., p46.

73 A number of US studies that have examined this, for example: R. Mehra (2003), "The Equity Premium: Why Is It a Puzzle?", in Financial Analysts Journal, vol.59, no.1; E. Fama and K. French (2002), "The Equity Premium", in The Journal of Finance, vol. LVII, no.2; and R. Arnott and R. Ryan (2001), "The Death of the Risk Premium" in Journal of Portfolio Management, vol.27, no.3.

74 K. Davis (1998), The Weighted Average Cost of Capital for the Gas Industry, Report Prepared for the Australian Competition and Consumer Commission and the Office of the Regulator-General.

75 SFG Consulting (2006), Response to Final Decision, Access Arrangements for SA Gas Distribution: Cost of Capital Issues, Report Prepared for Envestra.

76 ibid., p.55.

> However, whether this translates into a decline in the market risk premium is contentious. Transaction costs reduce the liquidity of an asset because it costs the investor more to alter their position. But it has not been established that, for the broader equity market, an illiquidity premium contributes a substantial amount to the observed market risk premium. In other words, a reduction in transaction costs does not necessarily translate into a one-for-one reduction in investors' required returns for holding the asset.

If there is clear evidence to demonstrate that structural change has occurred, and that it has impacted the value of the MRP, then it would not be appropriate to use a longer-term historical average that referenced data prior to the point in time when the structural change occurred. To date, however, no evidence has been produced to demonstrate the impact of these influences on investors' risk and return expectations, or the potential quantum of such an impact on the MRP.

Trends in the MRP

Another way of examining possible changes in the MRP is to seek to identify the extent to which the MRP has exhibited trends historically (including the more recent period when the MRP has purportedly fallen), or whether in fact it remains largely random.

In Figure C.2 the MRP appears to follow a random pattern with as many ups as downs. Table C.3 below details the ten major up and down years.

Table C.3 MRP over Last 106 Years: Ten Major Up and Down Years

Bottom 10		Top 10	
1982	-38.9%	1972	26.2%
1974	-32.3%	1936	26.3%
1952	-30.7%	1933	32.4%
1930	-28.5%	1943	32.5%
1988	-21.3%	1986	34.0%
1970	-16.6%	1987	34.4%
2003	-13.1%	1951	35.7%
1916	-13.0%	1960	35.8%
1931	-12.2%	1980	63.4%
1942	-11.9%	1968	75.7%

Data source: Bloomberg

The worst year in the 106 year period was 1982 and the year with the highest MRP was 1968. Over the last twenty years there have been two years in each of the top and bottom ten: 1988 and 2003 for down years and 1986 and 1987 for the up years. Over the last fifty years there have been five years in the bottom ten and six years in the top ten.

This is a fairly consistent result compared to the last twenty years. The up and down years appear to be reasonably and randomly spread.

A runs test[77] was conducted to determine randomness. The conclusion of the analysis was that with a Z factor of 1.37 the behaviour of the MRP was no different to the behaviour of numbers in a table of random numbers. There are no discernable trends or patterns that what one would not expect to find randomly. To the extent that the year-on-year value of the MRP therefore exhibits the characteristics of randomness, we cannot conclude that the MRP has trended downwards.

If the MRP is not trending downward, there is no statistically significant evidence to justify the market risk premium has moved below 6%.

C.3.3 The MRP: reconciling the positions

The best estimate of the 'true' long run market risk premium is the current long-run market risk premium. The MRP is volatile and as such a long-term average needs to be calculated to estimate a meaningful premium. It appears that the period of averaging needs to be at least 40 years and while longer periods change the calculated answer marginally, the advantage of a stable estimate outweigh any disadvantages of the longer time horizon.

This position holds provided there is no evidence of structural breaks that have resulted in a permanent change in the way that investors assess risk and return. If such a change can be identified, the evidence needs to demonstrate that the change has impacted the way that investors assess risk and return and how this has affected the value of the market risk premium. If this can be demonstrated, the relevant horizon for the estimation of the MRP will be the period since the structural break has occurred (presuming that investors' risk and return expectations were revised at the same time). However, as noted above, shorter-term estimates can be volatile and will be vulnerable to estimation error, so there will be considerable uncertainty underpinning any revised estimates.

There are arguably a number of changes and/or periods through time that could lead one to hypothesise that the value of the MRP has changed. However, to date sufficiently compelling empirical evidence has not been produced to demonstrate that this has occurred. To the extent that arguments that the MRP has fallen have emanated from recent observations of the MRP that have been estimated over a relatively short

77 A runs test is used to test data for randomness. It counts the frequency of runs of various lengths, where a 'run' could be a sequence of numbers with the same sign (eg a series of positive numbers). A certain number of runs is expected for the data to be seen to be random.

time period, our analysis has clearly shown that the MRP is inherently volatile, and caution should be exercised before drawing any conclusions based on such recent estimates. Further, given this short-term volatility, studies over longer horizons will be needed before any conclusions can be drawn regarding the possible permanency of changes in the MRP.

While the MRP is volatile in the short-term, over the long-term it has remained relatively stable with a number of studies suggesting that this value is at least 7%, which is around the mid-point of the 6% to 8% range that is commonly cited (this estimate is also supported by our own analysis). Notwithstanding this regulators have consistently selected a value from the lower bound of this range.

There are no patterns in the MRP as changes conform to a random distribution. A suggestion that the MRP is low today simply means that there has been a draw from a few poor years, which is likely to be followed by a few good years. Using a low MRP today means that one will need to use a high MRP tomorrow so that over time the average reverts to the long-term estimate. While we may have good years and bad years, removing the observations in the tail has little effect on the long-term average.

C.3.4 Conclusions

It is clearly evident that there is considerable uncertainty surrounding the estimation of the MRP. In the short-term, the MRP is volatile and caution should therefore be exercised in attributing trends based on estimates produced over short horizons.

Until there is sufficient empirical evidence to quantify the potential impact of structural change on the MRP, long-term historical estimates remain the most appropriate benchmark for the MRP. This average should not be adjusted for ad hoc events or hypothetical trends. Over the long-term, just as the market moves in cycles, we will also continue to experience 'good' and 'bad' events that will have a short-term impact on the MRP.

Given this inherent uncertainty particular caution needs to be exercised when seeking to nominate point estimates within a range. If point estimates are to be nominated, it is not prudent to select an estimate from the lower bound of this range. We believe a value of between 6% and 7% remains a reasonable range for the MRP.

D Gamma

D.1 Background

Prior to the introduction of dividend imputation in Australia on 1 July 1987, corporate profits were subject to double taxation: once at the corporate level and again at the personal level, through the taxation of individuals on their personal income from dividends. The imputation system removed this, allowing the proportion of tax collected at the corporate level on profits distributed to shareholders to be now rebated as a credit against the personal tax liabilities of the shareholder, if an Australian tax-paying resident (or other eligible entity, such as a superannuation fund).

The proportion of tax paid at the corporate level on the distributed profit is called the franking proportion and its associated credit is the franking credit. It is clear that different shareholders value franking credits differently, as their tax status determines whether their credits are able to be redeemed.

A quantification of the market's value of franked dividends is a direct input in the calculation of company cash flows and/or cost of capital. A company evaluates projects based on after-tax cashflows (where 'tax' represents the corporate tax paid). As gamma is essentially a prepayment of personal tax, an adjustment therefore needs to be made so that only the corporate tax is reflected in these cashflows.

Officer[78] shows that the adjustment to be used is gamma (γ), which is the proportion of the marginal shareholder's personal income tax on their income from dividends that has been prepaid at the corporate level (or, the proportion of corporate tax paid which can be claimed as a tax credit against personal tax). It will take a value between zero and one.

Despite its importance, there exists considerable disagreement on estimates of the value of franking credits, including the most appropriate means to value them. This contention has been particularly evident in regulatory decision-making. A value of 0.5 has been consistently applied. It is likely that this has occurred because:

- at the time that this issue was first examined by Australian regulators, there is some evidence to suggest that gamma may have had some value and that the value would lie somewhere between zero and one, with 0.5 being the mid-point.

[78] R. Officer (1994),"The Cost of Capital of a Company under an Imputation Tax System" Accounting and Finance, 34, 1-17.

Importantly, these early decisions were made prior to the introduction of the 45-day rule, which is discussed further below; and

- with mixed evidence as to what this value might be, regulators settled on the mid-point, being 0.5.

It has now become regulatory precedent, notwithstanding there is increasing evidence to suggest that the value may now be zero, or at least close to zero, particularly following the introduction of the 45-day rule that has now essentially precluded foreign investors from being able to derive any benefit from franking credits. More recently, regulators such as the QCA have resisted any change by rejecting the proposition that the marginal investor is a foreign investor and arguing that in order to accept this one would require application of an international CAPM.

This section is structured as follows:

- an overview of dividend imputation;
- assessing the value of gamma;
- an overview of the recent literature that has sought to estimate the value of gamma; and
- an analysis to test whether the market does in fact place some value on franking credits.

It will conclude that there is no evidence to suggest that the market now places any value on franking credits (where the marginal investor is foreign), and hence a value of zero is the most appropriate assumption for gamma.

D.1.1 An overview of dividend imputation

The value of franking credits is determined at the level of the investor and influenced by the investor's tax circumstances. Both Hathaway and Officer[79] and Cannavan, Finn and Gray[80] identify two separate inputs to estimating gamma, being:

- the distribution rate; and
- the value of franking credits.

[79] N. Hathaway and R. Officer (2004), "The Value of Imputation Tax Credits: Update 2004" Unpublished Working Paper, Capital Research Pty Ltd.

[80] D. Cannavan, F. Finn and S. Gray, (2004). "The Valuation of Dividend Imputation Tax Credits in Australia" Journal of Financial Economics, 73, 167-197.

These two inputs are related to gamma by the equation:

$$\text{gamma} = V \times D$$

where V is the value of franking credits[81] and D is the distribution rate.

Based on statistics supplied by the Australian Taxation Office, Hathaway and Officer estimate that approximately 71% of franking credits are distributed to shareholders.[82] However, only 32% of the distributed franking credits were redeemed.[83] This suggests that a significant number of shareholders did not utilise, or were unable to utilise, their franking credits.

Imputation credits are only available in respect of company tax paid on income subject to Australian taxation. For gamma to equal one all income must be domestically taxable. What is clear is that different shareholders value franking credits differently, as their tax status determines whether their credits are able to be redeemed.

If the shareholder is an Australian taxpayer, then they are subject to Australian personal income tax and can offset the prepayment of this tax at the corporate level against their own personal liabilities. If they are not subject to Australian personal income tax, such as non-residents and tax-exempt individuals or entities, then the company tax paid cannot be offset, and no additional value is therefore derived.

In relation to the redemption of credits, the major issue in the literature is therefore whose ability to redeem imputation credits is relevant for the assessment of the value of gamma. This is considered in the following section.

D.2 Key issues in assessing the value of gamma

D.2.1 The identity of the marginal investor

Officer's seminal work on dividend imputation specified that gamma is the proportion of the *marginal* shareholder's personal income tax on dividend income that had been prepaid at the corporate level (rather than the average shareholder's). The marginal shareholder is the price-setting investor. The price at which this shareholder transacts becomes the market clearing price, or the price equating the demand for capital by the firm with supply. It is this market-clearing price that will determine the firm's cost of capital.

81 φ is used instead of V in a number of studies

82 N. Hathaway and R. Officer (2004), op.cit.

83 Australian Taxation Office (2005), "Taxation Statistics 2002-03", Australian Government.

The key question is therefore the identity of the marginal investor. In open capital markets such as Australia, which have large capital requirements but an insufficient internal capital source, external capital must be drawn upon. In the context of imputation credits this means that both foreign and domestic investors will hold shares in Australian companies.

As noted above, non-resident shareholders are unable to derive any direct benefit from franking credits. Previously this could be indirectly derived via the trading of shares around dividend dates. Schemes were established by investment banks to allow foreign investors to extract value from franking credits, which relied on these investors selling their shares to domestic investors in the period leading up to the payment of the dividend (that is, before the shares go 'ex dividend', which is when the holder is no longer entitled to receive that dividend). The domestic purchasers would receive the cash dividend and franking credit, and subsequently sell the share back to the foreign investor at a small premium.

Some twelve years after becoming aware of these schemes the Commonwealth Government changed the Australian taxation law to introduce a minimum period of holding, requiring that shareholders have to be 'at risk' for a period of time in order to obtain the benefit of franking credits. This amendment, called the 45-day rule, was effective from 1 July 1997, although was not introduced until some time later (July 1999).

Under this law, investors are required to hold shares for a period of 45 days during a qualification period around the dividend event (without substantial hedging) in order to be eligible to rebate franking credits against their tax liabilities. This therefore significantly extended the window over which the previous trades between foreign and domestic investors could be made, to the extent that the extra price risk borne by the parties meant that such transactions were no longer worthwhile.

As a consequence, the return to a foreign investor comprises dividends and capital gain only, whereas the return to a domestic investor comprises dividends, capital gain and franking credits. If both foreign and domestic investors had the same expectations about the future earnings of the firm, which is a well-established tenet of economic theory, then the foreign investor would demand a lower price than the domestic investor, as the foreign investor receives a relatively lower return.

Therefore, in the presence of insufficient domestic capital it is expected that foreign investors shall be the marginal investors. As outlined above, even if the clear majority of the shareholders are domestic but there is some reasonable presence of foreign investors, then economic theory dictates that the marginal investor will be foreign because this investor will set the market-clearing price that determines the cost of capital.

In Australia, one can therefore conclude that as the price-setting investor in the 'average' firm is most likely to be foreign, franking credits are now worthless.[84] While they may have had some value prior to the introduction of the 45-day rule, there is no longer any basis for foreign investors to derive any benefit from these credits and their value will therefore be zero.

It should be noted that the notion that the marginal investor is foreign has not necessarily been accepted by regulators. There are two arguments that have been made here by regulators. Firstly, many regulated businesses have a 'unique' domestic shareholder base (for example, they are government owned businesses) and hence the marginal investor won't be a foreign investor. However, this argument is erroneous as WACC parameters are determined with reference to an 'efficient' benchmark firm. For the reasons outlined above, it is appropriate to conclude that such a firm would have at least some of its shares held by foreign investors.

Secondly, it has been proposed that if we are to consider the presence of foreign investors, we should be using an international CAPM to determine the WACC, not a domestic CAPM (and hence, all parameters would need to be respecified in a global market context). For example, the QCA submitted this argument in two recent final decisions, being Queensland Rail and the Dalrymple Bay Coal Terminal, stating that if a choice is to be made, the domestic CAPM should be used as an international CAPM will produce a lower WACC and hence disadvantage the infrastructure owner. This issue was explored in more detail in section 3.3.1, where it was shown that the most appropriate model to use is the domestic CAPM and that standard practice is to recognise the presence of foreign investors in estimating parameters such as gamma (in other words, this application of the domestic CAPM serves as an appropriate proxy for an international CAPM where markets are partially, but not fully, integrated). Excluding their influence is both unrealistic and impractical.

Further, a recent paper by Gray and Hall[85] (2006) finds that setting gamma to zero does not, unlike the values of gamma maintained by regulators, violate the deterministic relationship between the value of franking credits, the market risk premium and the corporate tax rate. Thus, taking gamma of zero is both agreed to by the theory and empirical bulk, and also is robust to the applicability of this assumption.

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[85] S. Gray and J. Hall (2006), "The Relationship Between Franking Credits and the Market Risk Premium", Accounting and Finance, 46, 405-428.

D.2.2 Other Australian tax law changes

There are a couple of other changes to the Australian tax law that are also cited as potentially impacting the value of gamma. However, these changes will only impact the value of gamma from the perspective of domestic investors, not foreign investors. Hence, they will only impact the value of gamma if the marginal investor is a domestic investor.

The first is the change in the relative tax treatment of dividends versus capital gains. Historically, the payment of dividends was often preferred over capital gains by investors given the adverse taxation treatment of capital gains. However, since this capital gains tax treatment has been halved, the retention of dividends by companies has been viewed positively by investors, given the capital gains tax consequences of subsequent increases in the share price are not seen as so severe. This could therefore have resulted in a reduction in the value of gamma to domestic investors.

Another significant change was the introduction of a tax rebate for unused franking credits in 2000. This meant that franking credits that previously could not be utilised (as they exceeded the individual's personal tax liability) now have some value. This should have increased the value of gamma to domestic investors.

While both of these changes may have had an impact on the value of gamma to domestic investors, and assist in explaining changes in the value of gamma to the *average* investor, this will have no impact on the value of gamma for cost of capital purposes if the *marginal* price-setting investor is not a tax-paying resident. The changes are therefore of no relevance when estimating the value of gamma for cost of capital purposes.

We will now provide an overview of some recent Australian studies that have sought to estimate the value of gamma.

D.3 Overview of the literature

The introduction of the 45-day rule is a significant and permanent structural change to the Australian market. It is significant because prior to the introduction of this rule, foreign investors could derive some benefit from franking credits by trading their shares with domestic investors around dividend dates. Although this benefit may not necessarily have been equivalent to the full value, this suggests that these credits had at least some value to these investors.

Foreign investors were never able to directly benefit from franking credits - these credits were only valuable to them to the extent that they could be sold to resident tax-paying investors that could utilise them. As it is no longer possible for foreign investors to 'sell' these credits, they are now worthless to them.

In examining the literature, the main focus will be on more recent studies, particularly those undertaken since the introduction of the 45-day rule (which, as noted above, was effective from 1997 yet only introduced in 1999). In 'dissecting' the literature in this way, it is important to note that the key issue is the time period over which gamma was valued.

Most of the later studies span both time periods. To the extent this is the case, and if it is accepted that the value of gamma has fallen significantly since the 45-day rule came into effect (perhaps to zero), this will produce an upward bias in the results of these studies. Studies undertaken prior to the introduction of the rule will also briefly be examined. Before these studies are examined, a brief overview is provided of one of the most common methodologies that has been used to estimate the value of gamma.

D.3.1 Dividend drop-off studies

One of the most commonly applied methodologies used in studies that have sought to estimate the value of gamma is the dividend drop-off approach. As a firm's share price will typically fall following the payment of a dividend (which is seen to be driven by the activities of short-term arbitrage traders), dividend drop-off studies examine the amount of the price change.

The difficulty here, however, is that it is extremely difficult to decompose this change into the value of the dividend itself and the value of the franking credits that are attached to that dividend. These variables are highly correlated, posing a number of methodological challenges for these studies. The reason for this correlation is that franking credits are linearly determined by the value of the cash dividend, as shown by:

$$FC = Div \times f\left(\frac{t}{1-t}\right)$$

Where:

FC = franking credit

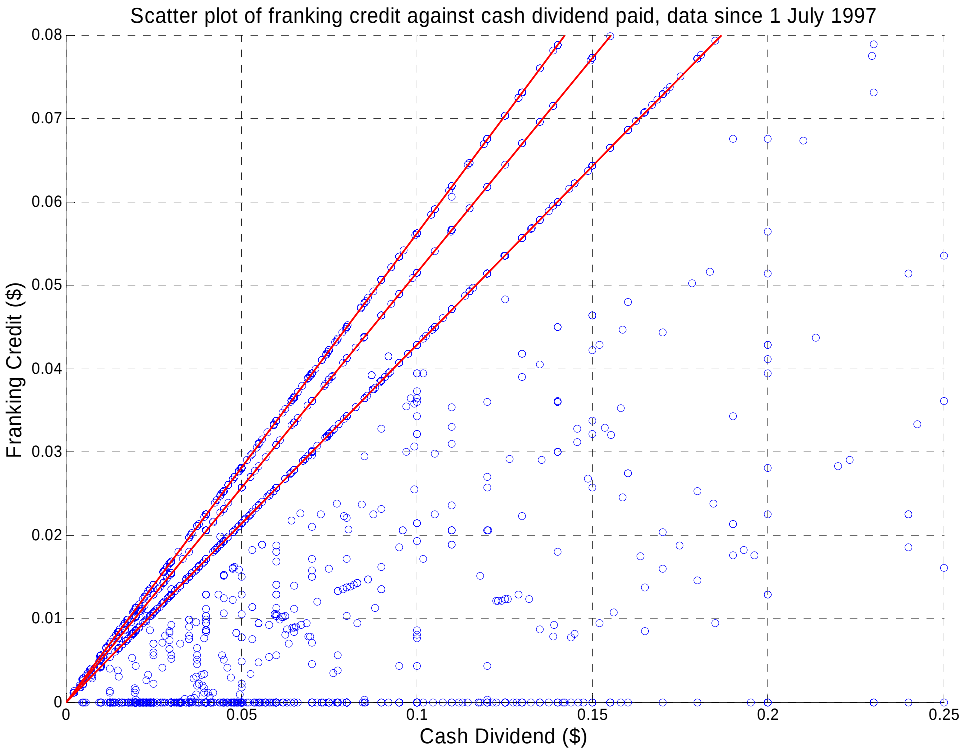
Div = cash dividend

f = franking proportion (or proportion of personal tax pre-paid at the corporate level)

t = the contemporaneous corporate tax rate.

This relationship can also be observed by plotting the two variables against each other, as shown in Figure D.1 below.

Figure D.1 Plot of Franking Credits against Cash Dividends Paid



Note: This data is for the ASX S&P 200.

The chart demonstrates the positive linear relationship between franking credits and cash dividends. The lines are the franking credits corresponding to fully-franked dividends at the 36%, 34% and 30% corporate tax rates experienced throughout the sample period (the slope of each line corresponds to the relevant tax rate).

This relationship will lead to a problem called multicollinearity and its presence will significantly reduce the ability to interpret the value of the estimates.

Regression analysis is used to test the existence and strength of the relationship between a dependent variable and one or more independent variables (in this case, our two independent variables are dividends and franking credits). The results of the regression will tell us the extent to which changes in the dependent variable are explained by the independent variables. If the independent variables are related, it will not be possible to isolate the impact of each of these variables in interpreting that relationship – this is multicollinearity.

It is therefore extremely important to keep this issue in mind when examining the results of dividend drop-off studies.

It is also important to note that most studies (at least in the first instance) seek to establish a value for franking credits (V). As noted above, this must be multiplied by the distribution rate to obtain a value for gamma (γ). Where we have done this below, we have assumed a distribution rate of 71%.

D.3.2 Studies prior to 45-day rule

Brucker, Dews and White (1994)

This was one of the first studies that applied the dividend drop-off methodology.[86] Their procedure involved regressing the drop-off (or the reduction in the share price) against the dividend and the face value of the franking credit. The estimated value of the franking credits was 33.5 cents per dollar of face value for the period 1987-1990, increasing to 68.5 cents per dollar of face value for the period from 1990 to 1993. Assuming a distribution rate of 71%, this equates to a value for gamma of 0.24 and 0.49 respectively.

Gray and Hall note four fundamental flaws with the methodology used here:[87]

(a) The confidence intervals are too wide for the results to be able to be meaningfully interpreted.

(b) As only two observations were available each year for each company, a cross-section of results was produced across all companies. As gamma is likely to vary for each company depending on the nature of the shareholding, the results cannot be meaningfully interpreted.

(c) Changes in price around the dividend date will be driven by short-term arbitrage traders. Any estimates would therefore represent the value of gamma to this class of investors. This is not necessarily the value that would be attributed to gamma by long-term investors, who are of most relevance in the context of estimating the cost of capital.

(d) As noted above, the two explanatory variables, being dividends and franking credits, are highly collinear. They conclude:[88]

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86 Brucker, Dews and White (1994), Capturing Value from Dividend Imputation, McKinsey & Co Report.

87 S. Gray and J. Hall (2004), Evidence on the Value of Franking Credits: A Report Prepared for City West Water, Melbourne Water Corporation, South East Water and Yarra Valley Water, Strategic Finance Group, p.5.

88 Ibid., p.6.

> The question is then one of how best to decompose this joint effect. A large body of evidence suggests that cash dividends are fully valued by those who trade around ex-dates. If this piece of evidence is coupled with the estimate of the joint effect of dividends and imputation credits, the implication is that imputation credits have negligible value. Thus, although this paper has been used to motivate the use of relatively large values for gamma, proper interpretation of the results would suggest the opposite.

Partington and Walker (1999)

One of the criticisms of dividend drop-off studies noted above is that using ex-date[89] data to estimate the value placed on franking credits by the market may result in measurements that are not representative of the value that long-term providers of capital may place on gamma. There can also be substantial price error, given an entire trading day elapses between observations.

Partington and Walker examined what was a relatively new innovation in trading on the Australian Stock Exchange, namely the ability to trade shares cum-dividend in the ex-dividend period.[90] Their methodology centered around comparing the price of cum-dividend stocks (that will entitle the holder to dividends and franking credits) with the contemporaneous price of ex-dividend stocks (that don't carry such entitlements) in order to back out the instantaneous drop-off ratio, which was the ratio of the difference between the cum-dividend and ex-dividend stock price to the cash dividend.

Sample data used by Partington and Walker spanned the period from January 1995 to March 1997, was restricted only to shares which paid fully-franked dividends and to trades that were at most one minute apart (in order to capture the contemporaneousness). This resulted in 1015 matched pairs of cum-dividend/ex-dividend trades after a number of innocuous filters were applied. The fact that this sample contained data prior to the introduction of the 45-day rule is of great importance in terms of the results, which were that:

- 95.8% of trades result in a ratio between 1 and the upper bound for a fully-franked dividend with fully-valued franking credit. Those that do not lie within this range can be explained by the size of the dividend, so even small market movements could mask price changes due to the dividend;

89 'Ex-date' refers to the date when the share goes ex-dividend. 'Ex-dividend' is when the dividend has been paid, so a purchaser of the share on or after this date is not receiving an entitlement to that dividend payment. The share price will immediately fall as a consequence.

90 G. Partington and S. Walker (1999). "The Value of Dividends: Evidence from Cum-Dividend Trading in the Ex-Dividend Period", Accounting and Finance, 39, 275-296.

- simple statistical tests (t-test and Wilcoxon signed rank test) confirmed that the mean drop-off was significantly greater than one at all commonly-accepted levels of significance; and
- the value the market places on franking credits was also backed out from these results and found to be 0.96 on average for trades, and 0.88 on average for events. These values were incorrectly reported as gamma. If the distribution rate of 71% is applied, the value of gamma would be 0.68 and 0.62 respectively.

Whilst these results are of questionable relevance in the period after the introduction of the 45-day rule, they help to reconcile the results of other studies. These results strongly suggest that in the period prior to the introduction of the 45-day rule the market did indeed value franking credits.

In addition to the implications of the 45-day rule, there is the chance for substantial sampling bias. Cum-dividend trading in the ex-dividend period is only available at a stockbroker's request. Combined with Partington and Walker's evidence that this trading is driven by either investors looking to capture franking credits and dividends, or option traders who are restricted to stocks which paid only fully-franked dividends (and is skewed towards the banking sector), it is highly likely that the participants in these trades are not representative of long-term capital providers, on average.

D.3.3 Most recent studies

Hathaway and Officer (2004)

Hathaway and Officer studied the relationship between the price change on the ex-dividend date and the cash dividend and franking credit paid, using data from 1988 to 2002.[91] Their methodology sought to isolate the additional drop-off in the share price that is attributable to the franking component from the drop-off that is due to the cash component. This relies upon decomposing the ex-date price change and regressing it against its components, in accordance with the following equation:

$$\Delta P = Div + FC + e$$

where:

ΔP = price change on the ex-date

[91] N. Hathaway and R. Officer (2004), The Value of Imputation Tax Credits: Update 2004, Unpublished Working Paper, Capital Research Pty Ltd.

Div = cash dividend paid

FC = franking credit paid with the cash dividend

e = error term.

A number of transformations of this equation are used by Hathaway and Officer to control for factors such as the market return on the ex-date and heteroskedasticity[92]. The regressions were run for all stocks in the ASX S&P 500 from August 1986 to August 2004, covering 6870 drop-off events. The regressions are run for small, medium and large firms as well as for high-yield stocks only.

They draw conclusions from the large firms for the purposes of reliability, and take credits to be priced at around 50% of their face value, giving an estimate of gamma of 0.355. In addition, they find that the market values cash dividends at around 80% of their face value. The conclude that: [93]

> We would be the first to admit that the value of imputation credits is not measured with any precision, but neither are many attributes of investment decisions which, by definition, must depend on future outcomes. Notwithstanding this lack of precision, ignoring them is tantamount to assuming a zero value for credits and this is certainly a gross error.

There are three key issues with this study. Firstly, as noted previously, one of the main problems with studies of this nature is the collinearity between the two independent variables, being dividends and franking credits. In fact, the two would be perfectly collinear if not for changes to the corporate tax rate.

The sample data contains only five changes to the corporate tax rate, and these only change the theoretical value of $1 of fully-redeemable credits by less than twenty cents. Indeed, for a sample of all firms in the ASX S&P 200 spanning the period between January 1996 and January 2006, the sample correlation coefficient between the cash dividend and franking credit was 94% which is far above the typical econometric "rule of thumb" threshold of 80%.[94] As the estimation procedure breaks down for highly correlated values and produces unreliable standard errors, great caution is required when investigating the results estimated by Hathaway and Officer.

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[92] Heteroskedasticity is where the error terms in an equation estimated from a data sample do not have a constant variance. It can be caused by the error term in a correctly specified equation, or the incorrect specification of the regression equation (eg, omitting a key variable).

[93] ibid., p.25.

[94] This is rudimentary and covered in many basic econometric texts, for example, Hill, Griffiths and Judge (2001)

Secondly, there are no levels of significance reported. Given the increase in standard errors encountered in regressions with high collinearity, the significance of the results is reduced. Furthermore, given the increased standard errors and strong linear association between dividends and franking credits, it is quite possible that the theoretical hypothesis that we have previously specified, being that the marginal investor is foreign and hence the value of gamma is zero, would not be able to be rejected.

Thirdly, the high degree of correlation between dividends and franking credits also means that a separation of their values is difficult. This is highlighted by the estimation of 80% as the market's value of the cash dividend, which lies in direct conflict with a large amount of academic literature. For example, Boyd and Jagannathan[95] suggest, with reference to the price decline for cash dividends, that a "one-for-one marginal price drop has been an excellent (average) rule of thumb" over the past few decades.

Hence, while they caution that assuming a value of zero for gamma could result in a 'gross error', they do not provide sufficiently robust evidence to prove that this value is not zero.

Beggs and Skeels (2005)

Beggs and Skeels used a similar approach to Hathaway and Officer, although producing different results.[96] Using data from the Commsec Share Portfolio database over the period from 1986 to 2004, they tested six tax regime changes on the value of franking credits, being:

- superannuation funds can use franking credits (1988);
- provisions to stop dividend streaming (1990);
- limits to use of franking credits by life assurance funds (1991);
- provisions limiting related payments, holding periods and delta hedging (1997);
- the reduction in capital gains tax (1999); and
- tax rebate for unused franking credits (2000).

Some notable results include that:

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95 J. Boyd and R. Jagannathan (1994), "Ex-Dividend Price Behaviour of Common Stocks", The Review of Financial Studies, 7, 711-741.

96 D. Beggs and C. Skeels (2006), "Market Arbitrage of Cash Dividends and Franking Credits", The Economic Record, 82, 239-252.

- from 1988 to 2001, the hypothesis that the estimated drop-off for the dividend and franking credit components are equal was rejected. This is seen to reduce the validity of models based on the gross drop-off ratio;[97]

- from 1987 to 1997, and for 2000, the value of franking credits was not shown to be significantly different from zero;

- since the last tax change (being the rebate on unused franking credits), the value of unused credits was seen to significantly increase. From 2001-2004, the value of the drop-off was 0.57. This translates to a value for gamma of 0.41; and

- the majority of the sample failed to reject the hypothesis that cash dividends are fully valued.

Whilst these results were found to be statistically significant, they should be interpreted with caution as the independent variables are again perfectly collinear, except for changes in the franking proportion and the corporate tax rate.

Bellamy and Gray (2004)

The study by Bellamy and Gray uses a similar methodology to that of Hathaway and Officer, but makes a variety of econometric extensions with an aim of improving robustness.[98] Whilst the rationale of Hathaway and Officer was preserved insofar as the stock price change was decomposed into cash dividend, franking credit and in some instances market return, eight models in total were estimated. These eight models differed in terms of whether:

- the ex-date price was kept raw or adjusted for expected returns;

- the dependent variable was defined as the drop-off ratio or the stock return; and

- the estimation was performed by ordinary least squares or weighted least squares. Under the latter, observations were weighted by their "informativeness", specifically, a higher weighting was given to higher-yielding, low-volatility stocks.

Data for the study was sourced from all stocks listed on the ASX between March 1995 and November 2002, containing 5640 dividend events in all.

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97 The gross drop-off ratio is the ratio of the change in price to the sum of the dividend and franking credit, that is, the change in price divided by the gross dividend.

98 D. Bellamy and S. Gray (2004), Using Stock Price Changes to Estimate the Value of Dividend Franking Credits, Working Paper, University of Queensland.

Bellamy and Gray conclude that the market places no value on franking credits and fully values cash dividends. They believe that the most robust approach to use was to adjust the ex-date price for expected returns, and give a higher weighting to more "informative" stocks (ie, higher yield, low volatility).

In arriving at this conclusion, they also noted that different research designs and sampling procedures can result in estimates for the value of franking credits anywhere between zero and 60%. Significant noise in security prices will result in a high degree of sampling error, even for large samples.

Further, while some recommendations are made about research design, it is not possible to separately and reliably estimate the value of dividends and franking credits. That is, irrespective of the adjustments made in an attempt to address multicollinearity, it will always be a problem. The correlation between the two in this sample was 0.85.

Whilst this study specifically pertained to the estimation of the value of franking credits and not gamma, it follows that if franking credits have no value to the marginal investor then gamma must be zero, irrespective of the distribution rate.

Cannavan, Finn and Gray (2004)

Cannavan, Finn and Gray seek to test whether the introduction of the 45-day rule has impacted the value of gamma.[99] Rather than use the dividend drop-off method, they sought to infer the value of cash dividends and franking credits from the relative prices of share futures and the underlying shares on which these contracts are written. They examined two securities traded on the Australian markets, namely Individual Share Futures Contracts (ISFs) and Low Exercise Price Options (LEPOs).

In a no-arbitrage framework[100], the following methods are equated:

- acquiring the share at a set time via futures contracts; and
- replicating this transaction in the physical market (which involves borrowing funds and purchasing the share).

Under this framework, a relationship between the spot price of the share, futures price, cash dividend and franking credit is derived. The ISF data spans the period May 1994

[99] D. Cannavan, F. Finn and S. Gray (2004). "The Valuation of Dividend Imputation Tax Credits in Australia", Journal of Financial Economics, 73, 167-197.

[100] A 'no-arbitrage' framework means that the two alternative strategies would be priced so that an investor is indifferent between them. If this is not the case, there is a potential arbitrage opportunity which investors could exploit, which would occur up until the point at which the advantage would be eliminated.

to December 1999 and data on LEPOs from April 1995 to December 1999 is used. Futures trades are only included when the underlying stock trades within four minutes of a futures trade, so this captures the contemporaneousness effect mentioned previously. In addition, the futures trades are made well-before the ex-date, so this reduces whatever effect short-term arbitrageurs may have, if any.

The authors noted that the data behaved well in-line with the no-arbitrage relationship and as such the model is substantially reliable. This is a key benefit over estimation via the dividend drop-off technique. The sample size is relatively small, given that there are only a small number of companies on whose shares derivatives contracts are written in the Australian market, and only the most highly-traded companies were included. However, any implications from a small sample size are likely to be outweighed by the benefits of using a more robust methodology.

In terms of overall conclusions, it is again found that the market fully values cash dividends, consistent with the theory.

The most fundamental conclusion is that after the introduction of the 45-day rule, the market does not value franking credits. In a manner similar to that of Bellamy and Gray, a constraint is also imposed in which the franking credits are given zero value after 1 July 1997. The finding that this constraint cannot be rejected is further support of the hypothesis that gamma is no longer valued by the market.

This study did find that franking credits were potentially valued at up to 50% of their face value prior to the introduction of the 45-day rule (suggesting a value for gamma of up to 0.36). Since then, however:[101]

> …we find no evidence of any positive value at all in imputation credits after the introduction of the 45-day rule. The increased costs and risks involved in transferring imputation credits make it infeasible to engage in this strategy even for the highest-yielding stocks…This means that in a small open economy such as Australia, the company's cost of capital is not affected by the introduction of a dividend imputation system. The company must produce the same return for the marginal stockholder whether an imputation system exists or not if the marginal stockholder receives no value from imputation credits.

The relationship between gamma and the market risk premium

A paper prepared by SFG Consulting discusses the relationship between the MRP and gamma and the implications of this for the regulated WACC.[102] They highlight how

[101] ibid., p.192.

estimates of the MRP only reflect the value of dividends and capital gains, but not the third potential source of return for investors, being franking credits. Using the standard framework developed by Officer, which is widely followed in Australian regulatory practice, they demonstrate the significant inconsistencies that arise with respect to the underlying assumptions implied by adopting a value for gamma of 0.5 and a MRP of 6%. In particular, the adoption of these parameter values implies a dividend yield "that is more than twice what we observe in the market."[103] The most robust way of resolving this inconsistency is to set the value of gamma to zero.

Box D.1 Market Evidence: Lonergan (2001)

How does the market value imputation credits?

In a study published in 2001, Lonergan reports the results of a survey of 122 independent experts' reports published between 1990 and 1999 which involved the use of a discounted cashflow methodology (and hence the estimation of a WACC) to assess the reasonableness of takeover bids. The purpose of this was to consider the extent to which adjustments had been made for dividend imputation.

Only 39% of these reports revealed the underlying WACC methodology, and of these 88% made no adjustment for imputation. Lonergan cites the various conceptual reasons that were given for doing this, which included:

- "the value of franking credits is dependent on the tax position of each individual shareholder ("To many shareholders, for example overseas shareholders, they have little value.");
- there is no evidence that acquirers of businesses will pay additional value for surplus franking credits;
- most diversified industrial companies already pay fully franked dividends, thus the values determined incorporate any effect of the value of dividend imputation;
- there is little evidence that the value effects of dividend imputation are being included in valuations being undertaken by companies or investors in the broader market;
- the evidence of the value the market attributes to imputation credits is not well developed;
- changes in tax legislation have made it much more difficult to trade in franking credits;
- foreign shareholders are the marginal price-setters of the Australian market and many such shareholders cannot avail themselves of the benefit of franchising credits;
- "the evidence gathered to date as to the value the market attributes to franking credits is insufficient to rely on for valuation purposes";
- even if imputation reduced the discount rate, acquirers would not pay any more than the value determined;
- there is no generally accepted method of allowing for dividend imputation. In fact, there is considerable debate within the academic community as to the appropriate adjustment or even whether any adjustment is required;
- there is a lack of certainty about future dividend policies, the timing of taxation and dividend payments and

102 SFG Consulting (2005), The Relationship Between Franking Credits and the Market Risk Premium, Brisbane.

103 ibid., p.3.

consequently about franking credits;

- while acquirers are undoubtedly attracted by franking credits, there is no clear evidence that they will actually pay extra for them or build imputation into values based on long-term cashflows;
- the studies that measure the value attributed to franking credits are based on the immediate value of franking credits distributed and do not address the risk issues associated with the ability to use them over the longer term;
- the fact that the entity utilising the imputation credit (if at all) is the underlying shareholders not the acquiring entity…
- empirical studies of dividend drop-off analysis reveal that smaller companies (whose ownership would generally include a greater number of individual shareholders theoretically able to use imputation credits) have the lowest gamma factor." (pp.13-14)

Reference: W. Lonergan (2001), The Disappearing Returns", Jassa, Issue 1 Autumn 2001.

D.3.4 Summary of results

The results of these studies are summarised in the following table:

Table D.1 Summary of Key Studies

Study	Methodology	Time Period for Estimation	Value of franking credits (V)	Value of gamma (γ)[a]
Bruckner, Dews and White (1994)	Dividend drop-off	1987-1990 1990-1993	0.34 0.69	0.24 0.49
Partington & Walker (1999)	Contemporaneous pricing of shares with and without franking credits	1995-1997	0.96 (average)	0.68
Hathaway and Officer (2004)	Dividend drop-off	1988-2002	0.5	0.36
Beggs & Skeels (2006)	Dividend drop-off	1987-2000,2000 2001-2004	0 0.57	0 0.41
Bellamy & Gray (2004)	Dividend drop-off (adjusted)	1995-2002	0	0
Cannavan, Finn & Gray (2004)	Analysis of futures and physical market (no arbitrage framework)	Pre- 45 day rule Post- 45 day rule	Up to 0.5 (high-yielding stocks) 0	0.36 0

a Assumes a distribution rate of 71%.

A number of studies have concluded that franking credits have some value, although the estimates vary considerably. More importantly:

- these studies include data from the period prior to the introduction of the 45 day-rule. This will produce an upward bias in the estimated value of gamma, given that franking credits would appear to have had some value prior to this change, and a zero value following the change; and

- a number of methodological issues have been identified. One of the most significant ones that is consistently encountered is the multicollinearity that will arise in dividend drop-off studies due to the strong relationship between the value of cash dividends and franking credits.

A number of studies have concluded that the value of franking credits is zero (or, we cannot reject the hypothesis that they have no value). One of the more notable recent works is the study by Cannavan, Finn and Gray, which, using a more robust methodology than dividend drop-off studies, concluded that since the introduction of the 45-day rule, franking credits are of no value to the marginal investor.

One implication of this is that it provides strong support for a gamma of zero, as if the value of franking credits is zero then so too must be gamma. However, for this to hold the marginal investor must be foreign and therefore unable to extract value from franking credits since the introduction of the 45-day rule. Tax law changes that only affect domestic investors, such as the introduction of a cash rebate for unused franking credits in 2002, should have no effect on the market's value of franking credits.

We now summarise the results of a relatively simple diagnostic test we have undertaken as a further test of the hypothesis that the value of gamma is not different to zero.

D.3.5 Simple diagnostic

In order to circumvent the host of econometric and sampling issues involved with estimating gamma, a basic and simple behaviour test can prove fruitful. The test aims to determine whether or not the market responds, on average, differently to franked dividends from how it responds to unfranked dividends. Whilst this may seem a different approach which does not measure the value of franking credits, it tests for the presence of their value.

In particular, it tests whether or not the ratio of the ex-date price change to cash dividends is significantly greater for franked dividends than unfranked dividends. That is, if it is found that shares with franked dividends behave in a manner that is not significantly different from shares with unfranked dividends on the ex-dividend date, this would lead to the conclusion that franking credits are valued at zero (leading to a zero value of gamma).

If, on the other hand, shares with franked dividends do behave in a manner that is significantly different, it would be concluded that this difference is due to the market placing value on franking credits. If this were the case, gamma would not be zero and further empirical investigations would need to be undertaken to estimate its value.

The data used in this investigation was sourced from Bloomberg and contains observations on firms listed in the S&P ASX 200 from January 1996 to January 2006. Trusts and other entities which have a dissimilar tax structure to companies were excluded, resulting in 3188 observations in total. Whilst this sample only spanned the top 200 stocks, because ex-date behaviour is analysed it is important to exclude thinly-traded stocks from the dataset (otherwise large errors may be introduced due to lags).

There is still considerable thinness in trading in this sample: of the 3188 observations, 36% (1140) have a delay of more than one day in price observations about the ex-dividend date. However, only 96 observations have a delay of more than three days, which takes dividends paid on Mondays into consideration and these were excluded. Partially franked dividends were excluded from the examination as this avoids complications in selecting an appropriate level of franking as the cut-off point.

For the full period, there were 516 events with unfranked dividends and 2138 events with fully franked dividends. The sample standard deviations of the drop-offs ratios were such that a test for equality of variance would conclude that the standard deviations of the samples were unequal[104]. As a consequence, the common parametric test for equality of means is invalid so the simple, non-parametric paired test is used instead.

The sample of fully franked events is substantially larger that that of unfranked events, so a random sample of it is taken to produce the same number of observations, which was then paired with the full set of unfranked observations. If the theoretical hypothesis is true (that is, the market value of franking credits is zero), it should be the case that half of the fully franked drop-off ratios are greater than the unfranked drop-off ratios.

There was found to be insufficient evidence to reject this hypothesis[105] and as such it is concluded that the market responds equally to fully franked and unfranked dividends. The same test is used for the sample of data from 1 July 1997 onwards as the parametric test is invalid[106] and the nonparametric test leads to the same conclusion[107]. This evidence that the market does, on average, respond equally to fully franked and unfranked dividends is further evidence that the market places no value upon franking credits.

[104] F-test for variance equality: $s_1 = 5.6736$, $s_2 = 1.9994$, p-value < 0.0001

[105] Paired sample test: sample proportion = 0.527, theoretical proportion = 0.50, p-value = 0.11

[106] F-test for variance equality: $s_1 = 6.0972$, $s_2 = 2.0996$, p-value < 0.0001

[107] Paired sample test: sample proportion = 0.528, theoretical proportion = 0.50, p-value = 0.12

This test can also be extended to see whether the drop-off for franked dividends behaves significantly differently from unfranked dividends if franking credits are valued at some proportion of their face value.[108] In this case, the proportional value will be 50% and 100%. In other words, rather than testing the hypothesis that the value of franking credits do not have a value other than zero, we are testing the hypothesis that these credits have some value. In this case, we have tested three values, being:

- 0.5;
- 0.7 (which is the value implied by a gamma of 0.5 and a distribution rate of 71%); and
- 1.

It has already been found that the market behaves the same way for franked and unfranked dividends on the ex-date, by only moving on average by the amount of the cash dividend. Therefore, if it is found that these new ratios are significantly different across franked and unfranked dividends then the market must not value franking credits. The sample data was again restricted to observations after 1 July 1997 and to fully-franked and unfranked dividends. The same nonparametric test is used and it is found that the ratios are different across fully-franked and unfranked dividends with a half-valued franking credit[109], a value 0f 0.7[110] and a fully-valued franking credit[111].

On this basis, we can reject the hypothesis that franking credits have a value of 0.5, 0.7 (which is implied by a value for gamma of 0.5 assuming a 71% distribution rate) or 1. In addition, we believe this is likely to be the finding irrespective of the value tested for the valuation of franking credits.

This inconsistency with the result for the ratio of price decline to cash dividend only is further evidence that the market does not value franking credits.

D.4 Conclusion

Gamma is the product of two inputs which must be estimated:

- the proportion of tax paid that has been distributed to shareholders as franking credits; and

[108] That is, rather than consider the ratio of price decline to cash dividend, the ratio of price decline to cash dividend and some proportion of the face value of the franking credit is considered.

[109] Paired sample test: sample proportion = 0.590, theoretical proportion = 0.50, p-value < 0.0001

[110] Paired sample test: sample proportion = 0.5907, theoretical proportion = 0.5, p-value<0.0001

[111] Paired sample test: sample proportion = 0.595, theoretical proportion = 0.50, p-value < 0.0001

- the value the marginal investor places on $1 of franking credits, referred to as the value of franking credits.

A number of studies have sought to estimate the value of gamma and the results vary considerably. The key concerns we have with some of these studies are that:

- studies using the dividend drop-off methodology need to be treated with extreme caution given the collinearity between dividends and franking credits. While Bellamy and Gray's methodology sought to adjust for this, they concluded that it is not possible to separately value the two;

- the introduction of the 45-day rule resulted in a major structural change that has fundamentally impacted the value of franking credits. Any studies that seek to estimate gamma using data prior to this date will over-estimate the value of gamma.

Recent robust empirical investigations have concluded that the value of franking credits is zero since the introduction of the 45-day rule (Bellamy and Gray, 2004; Cannavan, Finn and Gray, 2004). This is predicated on the key assumption that the marginal investor is foreign. We are of the view that it is appropriate to recognise the presence of foreign investors in the Australian market while retaining a domestic CAPM. This is because:

- an international CAPM is difficult to specify, and assumes that capital markets are fully integrated, which is not the case; and

- respecification of the domestic CAPM to exclude foreign investors is not only extremely difficult to do but ignores the practical influence that these investors do exert in the Australian market (reflecting the partial, but not full, integration of global capital markets).

The finding by Hathaway and Officer (2004) that franking credits are valued at around 50% of their face value can be discounted due to methodological issues, including:

- the multicollinearity problem, as outlined above, which also means that separately the (potential) values of dividends and franking credits is extremely difficult; and

- there are no levels of significance reported: given the increase in standard errors encountered in regressions with high collinearity the significance of the results is reduced.

Additionally, a basic but informative test of the market's behaviour with regards to the ex-date price response finds that for fully-franked and unfranked dividends, the market responded equally to the cash dividend only, which is further evidence of the worthlessness of franking credits.

As an extension to this model, it was tested whether or not franking credits were valued by the market at 50%, 70% and at 100% of their face value, which was emphatically rejected. All in all, there is insufficient evidence to reject the theoretical hypothesis that franking credits are worthless. Fundamentally, the implication of these findings is that gamma should be set to zero. This also means that there is no basis for adopting an assumption of 0.5.

To summarise, on the basis of the evidence we believe that it is appropriate to assume a value of zero for gamma. This evidence includes:

- evident difficulties in estimating a reliable value for gamma (which may be because it has no value);
- a strong theoretical foundation, being that since the introduction of the 45-day rule, franking credits are now of no value to the marginal foreign investor (whereas they may have had some value prior to this); and
- empirical evidence to support a value of zero, both from the recent literature and our own analysis which confirmed that we cannot conclude that gamma has a value other than zero.

Brief Biographies of Team Members

Euan Morton, Principal

Role: Peer review

Euan is an experienced economist and lawyer specialising in regulatory and competition issues. He advises extensively on pricing and costing issues in the water, energy and transport industries, including the estimation of WACC.

Euan was appointed to the Expert Panel by the Ministerial Council on Energy to review regulatory arrangements associated with the ongoing reforms to energy markets. He has been appointed by NEMMCO as an Independent Expert under the National Electricity Rules and is a member of the Trade Practices Committee of the Law Council of Australia.

Euan also has extensive experience advising on cost of capital issues in both regulatory and commercial applications, including in the energy, water and rail sectors.

Professor Jerry Bowman, Associate

Role: Peer review

Jerry Bowman is the Professor of Finance at the University of Auckland and is one of the most respected academics in the field of cost of capital in Australia and New Zealand. Jerry has advised a number of infrastructure providers in the energy, airports, rail and telecommunications sectors, including acting as an expert witness. Jerry has recently been involved with other leading academic thinkers in the development of alternative approaches to the estimation of the asset and equity betas for regulated businesses.

He has published a number of articles on issues relating to WACC, including the assessment of systematic risk, issues associated with the market risk premium and the implications of dividend imputation. Jerry is one of a number of co-authors of a recent report that was prepared for the Energy Networks Association that highlighted the empirical issues inherent in beta estimation and their significant consequences for the reliability of these estimates.[112]

[112] S. Gray, J. Hall, J. Bowman, T. Brailsford, R. Faff, R.Officer (2005), The Performance of Alternative Techniques for Estimating Equity Betas of Australian Firms, Report Prepared for the Energy Networks Association.

Mark Christensen, Associate

Role: Analysis

In addition to undertaking work for Synergies, Mark Christensen is a Senior Lecturer at the Queensland University of Technology and is also a Member of the Queensland Competition Authority. Mark is the co-author of *Fundamentals of Corporate Finance*, which is widely used in undergraduate university courses in Australia.[113]

Corporate finance, and in particular, WACC, is Mark's core area of expertise. Mark has advised a number of organisations on WACC in both commercial and regulatory applications. He has also developed and delivered a number of training courses on WACC issues and its applications. As a Member of the QCA, Mark is also required to provide input on WACC determinations.

Mark's experience includes the assessment of beta and beta calculations. For example, he was involved with a colleague in developing the AGSM beta files. The work required calculations for the market proxy and firm return calculations considering capitalisation adjustments, dilution factors and infrequency of trading adjustments. Mark has access to numerous sources of data including Reuters, Datastream and Bloomberg.

Recently Mark's research interests have focused on the valuation of gamma. He has also examined the small firm effect, in terms of what it is (that is, is it an anomaly or a methodological issue) and its implications for WACC.

Jo Blades, Director

Role: Analysis and drafting

Jo joined Synergies in 2005 after spending most of her career with the Queensland Treasury Corporation. While at QTC Jo was involved in the development and delivery of customer training courses in corporate finance, including cost of capital. Jo also co-ordinated QTC's submissions to the QCA and ACCC regarding the implications of the regulation of WACC on debt and interest rate risk management for QTC's regulated borrowers.

During her time at Synergies, Jo has been involved in providing advice to a number of businesses on a range of commercial and regulatory issues. This includes reviewing issues associated with the review of the cost of capital for regulated businesses as part

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[113] Ross, Thompson, Christensen, Westerfield and Jordan (2004), *Fundamentals of Corporate Finance*, McGraw Hill, Sydney.

of a regulatory review (in the rail and telecommunications sector). Major WACC reviews have also been undertaken for a business in the water sector and a port terminal.

Jo also spent eighteen months as an Associate Lecturer in the School of Economics and Finance at the Queensland University of Technology, teaching in undergraduate finance and economics courses.