VENCorp

Victorian Energy Networks Corporation

Major System Augmentation Report for the Victorian Principal Transmission System

November 2005

Contents

1. Executive summary

This report presents VENCorp's analysis of a number of gas pipeline expansion options to address future transportation limitations affecting Victorian gas consumers. Current growth in demand for gas suggests that from 2008 onwards gas users potentially face shortages because of insufficient transmission capacity to transport gas to consumers. This projected shortfall is largely driven by the growth in gas consumption by residential, commercial and small industrial customers using winter heating and hot water appliances. During winter peak days these sectors account for over 70 per cent of gas demand. However, because of the physical requirements of the gas system, Gas Power Generators (GPG) and large industrial loads will be first to have their gas supplies cut off in the event of a supply constraint. Expanding existing pipeline capacity will reduce the need to curtail gas consumption to these sectors and will ensure that all gas users continue to have a safe and secure supply of gas.

The capacity shortfall projected for 2008 was first identified in VENCorp's 2004 Gas Annual Planning Review (GAPR) using the 1 in 20 peak day gas planning standard. To address the emerging network limitation the standard suggested that a major system augmentation would be required before winter 2008 to increase overall system capacity and useable system linepack. Modelling at the time indicated that an effective option would be an extension of the 500 mm South West Pipeline (SWP) from Lara to Brooklyn (the "Corio loop"). However, the GAPR noted that a detailed assessment would be required to identify the most appropriate solution considering both the costs and benefits of alternative options to address the limitation.

This report presents VENCorp's detailed cost-benefit analysis of various options to address the emerging network limitation. The assessment has been conducted by VENCorp using a similar approach to that which it adopts in its assessment of electricity transmission network augmentations.

The options considered as part of the assessment include:

- Longford pipeline duplication (Longford loop);
- Corio to Brooklyn augmentation (Corio loop);
- Corio to Wollert augmentation;
- LNG facility duplication;
- Lara to Dandenong Sub-sea pipeline;
- Culcairn to Melbourne augmentation; and
- Stonehaven Compressor Station installation.

Following preliminary technical and economic assessments, two options were considered suitable for detailed technical and economic analysis: the Longford loop and the Corio loop. The preferred Longford loop option consists of a duplication of three of the four unduplicated sections of the 750 mm Longford pipeline and comprises augmentations from Drouin to Bunyip, Tyers to Gooding; and Yarragon to Drouin. The total length of the three loops is 47 km and the estimated cost is $ 55.5 million. The preferred Corio loop option is a 500 mm greenfields pipeline from Elcho Road to Hopkins Road and then along the existing Brooklyn Ballan Pipeline easement from Hopkins Road to Brooklyn. The length of this pipeline is 57 km and the estimated cost is $61.7 million.

The results of VENCorp's detailed analysis are summarised in Table E1.

Table E1 - Summary of net market benefits assessment

Option	Cost ($2005)	Net Market Benefits (NPV) ($2005)	Cost-Benefit Ratio	Optimal timing
Longford loop	55.5million	47.2 million	2.1	2009
Corio loop	61.7 million	93.1 million	2.9	2008

Table E1 illustrates that, despite the higher cost of the pipeline, the Corio loop has greater net market benefits at a higher cost-benefit ratio than the Longford loop. These higher benefits are primarily due to the increased system capacity and linepack arising from better utilisation of linepack already existing in the SWP. The Corio loop also provides greater access to the significant developments of new gas supplies in the Otway Basin which increases system security. As a result, VENCorp considers that it is the most suitable option to address the emerging network limitation.

Modelling based on the peak gas usage period of May to September indicates that the Corio loop maximises the benefit to the market if it is operational from May 2008. However, sufficient contingency must be provided in the construction of the project to allow for any unforeseen events. For this reason VENCorp supports the completion of the project by 1 March 2008.

2. Background

2.1 The Victorian PTS

The Principal Transmission System (PTS), depicted in Figure 1, is Victoria's primary high-pressure gas transmission system. It transports gas from Longford in the south-east of Victoria, Iona in the south west of the State along the SWP, and the inter-connection with the NSW system at Culcairn, north of Albury, to the Melbourne and regional demand centres.

Owned by GasNet the PTS comprises just over 1,930km of pipeline, with pipeline diameters ranging from 80 mm to 750 mm, operating at maximum pressures of up to 10,000 kilopascals (kPa).

Presently, there are five injection locations of gas on the PTS. They are the:

- Longford gas processing plant and VicHub in the south-east of the Victoria;
- SEA Gas Interconnect and underground storage facility at Iona in the south-west;
- Interconnection with the NSW system via Culcairn, north of Albury;
- Liquified Natural Gas (LNG) storage facility at Dandenong; and
- BassGas connection near Pakenham in the south-east, which is expected to commence operation in 2006.

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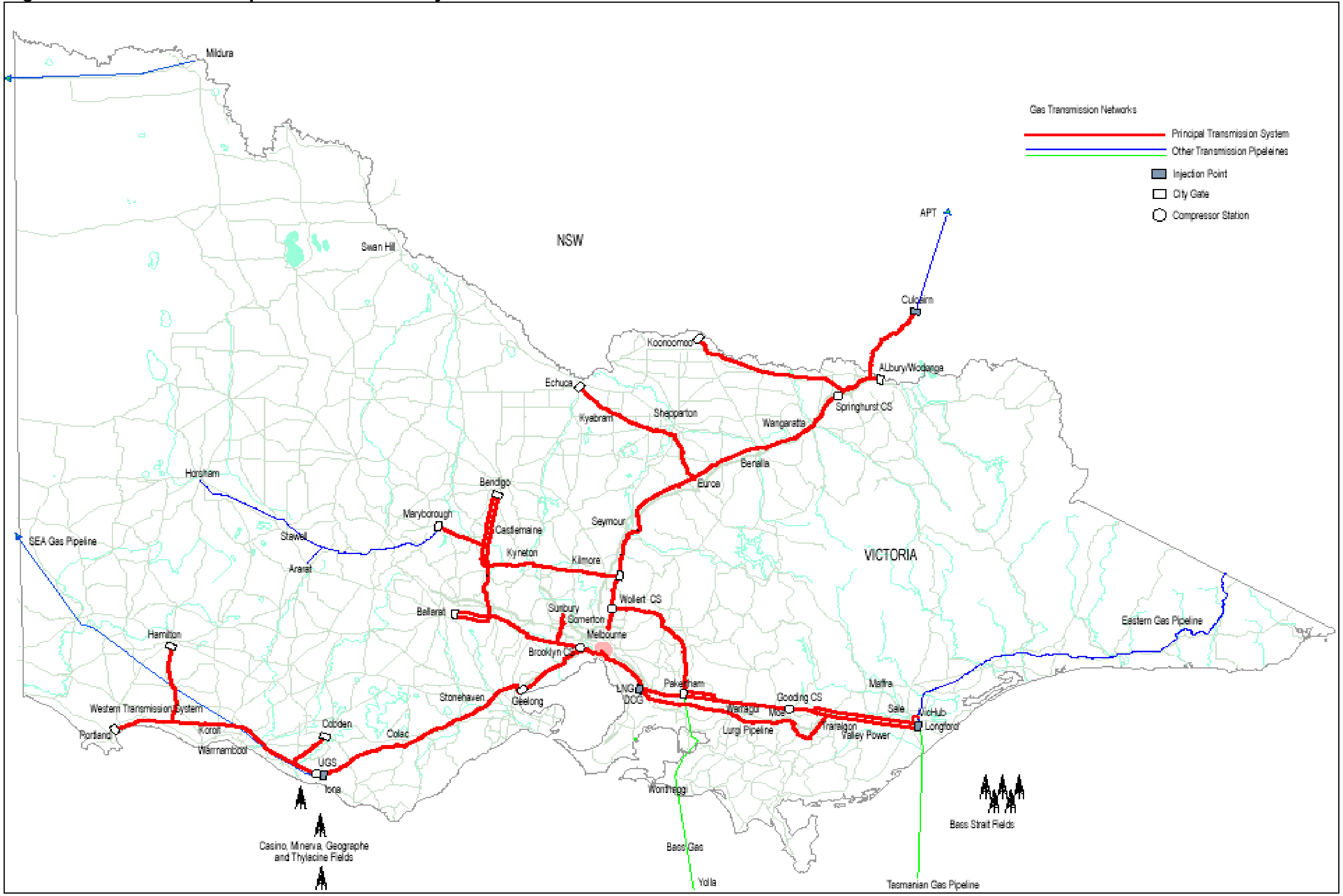
Figure 1 - Victorian Principal Transmission System



With multiple injection sources, storage facilities and interconnection to other pipelines, the PTS exhibits the characteristics of a meshed network rather than a point-to-point pipeline as is the case with most other Australian pipelines. Unlike other systems in Australia, the amount of linepack, which is the compressed gas stored in pipelines, is relatively low and this can result in within day supply-demand network constraints, particularly during winter.

2.2 The Victorian gas industry structure and VENCorp

2.2.1 VENCorp's gas industry and planning functions

Under the Victorian Gas Market model the roles and responsibilities for ownership and operation of the PTS have been separated. In Victoria, VENCorp is the independent system and market operator and has no direct financial interest in market outcomes. This ensures that operation of the pipeline system, the scheduling of market offers for gas injections and withdrawals and the release of market and system planning information is undertaken in an open and transparent manner.

VENCorp also has major planning and development roles in the gas market. As part of its planning and development roles, VENCorp produces a Gas Annual Planning Review (GAPR) each year. The GAPR is an independent planning study for the forthcoming five-year period which provides information regarding future development of the PTS, gas storage facilities and gas supplies for the Victorian Gas Market.

The information in the GAPR is provided for the primary purpose of allowing market participants and interested parties to make informed decisions related to planning of pipeline or production facilities and market strategies. The information presented in the GAPR includes:

- Demand forecasts for high, medium and low economic growth scenarios;
- Forecasts of gas supply and storage;
- The adequacy of transmission system capacity and the supply-demand capacity outlook;
- Monthly planning analysis; and
- A long-term network development scenario.

While VENCorp is required to provide planning information to the gas industry, it is not VENCorp's role to act on the information provided in the GAPR.

2.2.2 VENCorp's electricity planning functions

In the electricity market VENCorp is responsible for planning and directing augmentations to Victoria's high voltage electricity transmission network. It does not own any transmission assets and sources network services from the Transmission Network Service Providers (TNSPs) that own and operate the Victorian transmission system.

VENCorp's planning decisions are made based on an objective, probabilistic assessment using the regulatory test where both the costs and benefits of alternative options are considered[1]. It procures all major

[1] Australian Energy Regulator, Review of the Regulatory Test, August 2004.

transmission augmentations via an open competitive tender process whether it be network or non-network services. This model has proven to be an effective means of introducing competition and innovative solutions into the design, construction, maintenance, financing and long-term ownership of those solutions.

2.3 Planning criteria for transmission network expansions

VENCorp's current approach to identifying potential network augmentations to the PTS is based on the 1 in 20 winter peak day planning standard. It is expected this peak day demand forecast for defined severe weather conditions and operating conditions will be exceeded, on average, once in every 20 years.[2]

This contrasts with the approach adopted when planning augmentations to the electricity transmission network. VENCorp's electricity transmission network planning is aimed at ensuring that, following the loss of the most critical transmission element, including at times of peak demand:

- the security of the power system can be maintained;
- transmission plant ratings are not exceeded; and
- the network performance requirements in Schedule 5.1 of the National Electricity Rules are met.

In planning the electricity transmission network VENCorp accepts the possibility, albeit small, of load shedding. Therefore, VENCorp's investment decisions are based on a probabilistic analysis of energy at risk, which includes consideration of the probability-weighted impacts on supply reliability of unlikely, high cost events such as single and multiple outages of transmission elements and unexpectedly high levels of demand. VENCorp believes that its approach provides a sound actuarial estimate of the expected value of energy at risk. Implicit in the use of probabilistic planning is acceptance of the risk that there may be circumstances when the planned capability of the network will be insufficient to meet actual demand.

This probabilistic approach to electricity transmission network planning ensures that an economic balance is struck between:

- the cost of providing additional network capacity to remove any constraints; and
- the cost of having some exposure to loading levels beyond the network's capability.

In other words, recognising that very extreme loading conditions may occur for at most a few hours in each year, it may be uneconomic to provide additional electricity transmission network capacity to meet all anticipated loading requirements.

VENCorp believes that going forward, a similar approach should be adopted in its assessment of gas transmission network augmentations in those situations where a market based solution is not forthcoming. The 1 in 20 winter peak day planning standard can be used as a trigger for VENCorp to conduct a more detailed assessment of a network limitation identified as part of its GAPR. Following the identification of potential network constraint VENCorp would identify a range of options to address the limitation. Based on a high level assessment of the various options VENCorp would then undertake more detailed technical analysis of those options to ascertain whether they are appropriate solutions. Suitable options would then be costed and assessed using VENCorp's economic modelling to determine which option best meets the needs of the market. This process is depicted in Figure 2.

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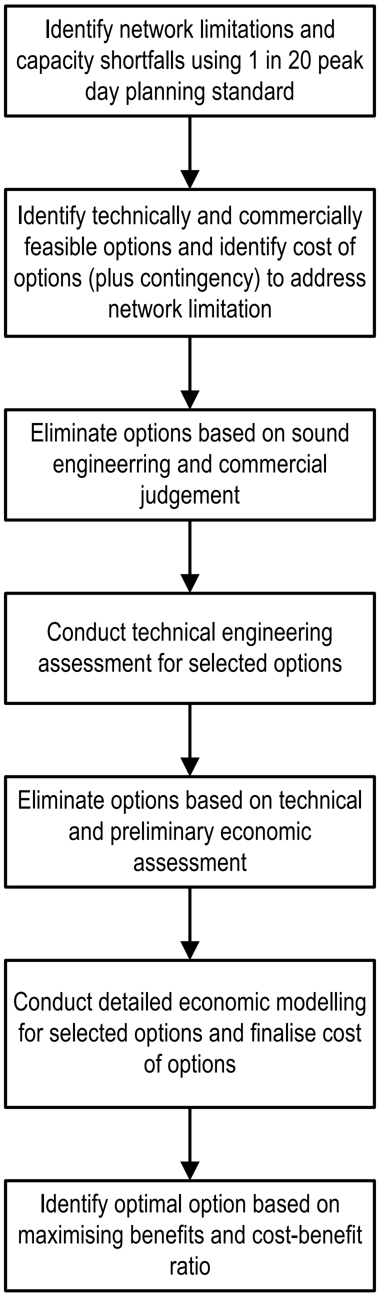
2 However, with GPG included this level can be exceeded in about 50 per cent of winters.

Figure 2 - Probabilistic planning process



2.4 Network expansions and the Gas Code

Clause 8.16 of the National Third Party Access Code for Natural Gas Pipeline Systems (Gas Code) sets out the process that a covered gas transmission business must comply with when seeking to roll in an augmentation into its asset base. The test specifies that:

> The amount by which the Capital Base may be increased is the amount of the actual capital cost incurred (*New Facilities Investment*) provided that:
>
> (a) that amount does not exceed the amount that would be invested by a prudent Service Provider acting efficiently, in accordance with accepted good industry practice, and to achieve the lowest sustainable cost of delivering Services; and
>
> (b) one of the following conditions is satisfied:
>
> (i) the Anticipated Incremental Revenue generated by the New Facility exceeds the New Facilities Investment; or
>
> (ii) the Service Provider and/or Users satisfy the Relevant Regulator that the New Facility has system-wide benefits that, in the Relevant Regulator's opinion, justify the approval of a higher Reference Tariff for all Users; or
>
> (iii) the New Facility is necessary to maintain the safety, integrity or Contracted Capacity of Services.

In essence the 'New Facilitates Investment' test is a two-stage process. First, it requires that a pipeline proponent initially demonstrate that the amount that it invested does not exceed an amount that would be invested by a prudent operator acting efficiently (the prudency test). The pipeline proponent must then demonstrate that the project satisfies at least one of three following conditions:

- the incremental revenue exceeds the incremental cost of the investment (incremental revenue test)
- the investment has system wide benefits (system wide benefits test); or
- the investment is necessary for the safety, integrity or Contracted Capacity of Services (system security test).

This report is prepared on the basis that the optimal investment identified in the detailed cost-benefit assessment will satisfy the aforementioned conditions. That is, that the cost of the project would not exceed the amount invested by a prudent service provider acting efficiently and that it has system wide benefits.

2.5 Pricing and Balancing Review

While VENCorp's preference is for market signals to encourage new investment decisions it is aware that this may not always be the case, particularly where there are incentives for the beneficiaries of an investment to 'free-ride' off the decisions of others.

As further background, this point was recognised by VENCorp as part of the work for its Pricing and Balancing Review whose recommendations were endorsed by the Victorian Minister for Energy Industries and Resources. In January 2004, VENCorp established a Pipeline Investment Working Group (PIWG) as part of the Pricing and Balancing Review to consider these pipeline investment issues. In April 2004, the PIWG published a paper recommending regulatory and transmission rights-based solutions[3].

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3 Pipeline Investment Working Group Paper, 8 April 2004

The recommended regulatory solutions were:

- To design a market benefits test (similar to the electricity regulatory test) as a change to or clarification of the Gas Code's system wide benefits test. The new test would allow tariffs to be increased where the market benefits from the investment exceeded its cost and where the beneficiaries of the investment could not be clearly identified because the benefits were too diffuse or system-wide;
- To apply a market benefits test where investment needs arise from general market growth, rather than from distinct new requirements of one or more shippers;
- For VENCorp to assess potential investments under the market benefits test as an expansion of its role in providing planning information through its annual planning review process and, where appropriate, VENCorp would then assist in the development of submissions to the regulator; and
- Where the regulator approves, ex ante, a proposed investment that has satisfied the market benefits test, for the cost of that investment to be rolled into GasNet's regulatory asset base[4].

VENCorp adopted the PIWG's regulatory recommendations in its Pricing and Balancing Review as a fall back in the event that the rights based solutions did not deliver appropriate market driven outcomes or, in the interim, if the rights based solutions were not fully developed[5].

The key regulatory investment recommendations of the Pricing and Balancing Review were for:

- VENCorp to develop a suitable market benefits test where beneficiaries of an investment are not easily identifiable and to pursue:
    - The relevant regulator accepting the market benefits test as a means of application of the Gas Code's system wide benefits test, or failing this, by means of a Code change; and
    - The relevant regulator providing binding "ex-ante" approvals of such investments thereby removing the risk of "ex-post" optimisation.

VENCorp considers that, in the interest of promoting regulatory certainty, that the market benefits limb of the electricity regulatory test be adopted by the Australian Competition and Consumer Commission (ACCC) as a means of interpreting the Gas Code's system wide benefits tests. Interpreting the system wide benefits test in this way would require the project proponent to demonstrate that benefits are quantifiable, in financial terms with externalities excluded, and that the Net Present Value (NPV) benefits of a new investment would exceed its cost (i.e. the investment is NPV positive)[6].

VENCorp believes that using the market benefits test in this manner aids the ACCC's interpretation of the system wide benefits test.

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4 op cit pp 1-2.

5 VENCorp, Pricing and Balancing Review, 30 June 2004.

6 For the purposes of this report VENCorp considers externalities to be those benefits which cannot be directly and easily quantified. This means that it has not included benefits such as meeting government greenhouse targets or benefits typically associated with general equilibrium modelling such as the effects of a more competitive energy market on Australian exports. For the avoidance of doubt competition benefits are not considered to be an externality.

2.6 System wide benefits test

Notwithstanding the recommendations of the Pricing and Balancing Review, given the type of benefits quantified in this report, which are set out in Chapter 6, VENCorp believes that the analysis and findings contained in this report are acceptable as conforming with the system wide benefits test. The majority of benefits arise from avoiding involuntary load curtailment. The cause of the increase in frequency and magnitude of system constraints is primarily due to growth in residential and small customer sectors. The proposed project, which, while predominantly affecting GPG and larger industrial loads, who because of the technical nature of the system are curtailed first, prevents a situation from arising that would otherwise threaten the security and integrity of the entire system and result in curtailment to smaller industrial and residential customers.

The other form of benefits arise from an increase in social (or economic) welfare resulting from greater inter-basin competition as a result of the network augmentation. Because of the difficulties associated with quantifying these benefits VENCorp has taken a conservative approach and not included theses benefits in the base case. They are, however, considered in one of the sensitivity tests.

3. Identification of network limitation

This section provides an overview of the demand supply sections of VENCorp's 2004 GAPR and outlines the processes and assumptions made to determine a network limitation.

3.1 Demand forecasts

This section provides a high level overview of the demand forecasts for the period 2005 to 2012. More detail can be found in VENCorp's 2004 GAPR.[7] [8]

VENCorp engaged the National Institute of Economic and Industry Research (NIEIR) to produce independent system annual and peak day gas demand forecasts based on Low, Medium and High economic scenarios. Table 1 shows NIEIR's forecast annual system demand with and without GPG.

Table 1 - Forecast annual demand (PJ)

	System Demand			System Demand and GPG[9]		
Calendar Year	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**
2005	209.3	211.8	215.6	217.8	221.2	225.1
2006	211.2	215.8	222.0	220.7	226.8	235.0
2007	213.8	220.4	229.2	225.1	233.5	246.3
2008	215.2	223.3	235.9	228.3	238.3	258.2
2009	216.0	226.1	242.8	230.0	242.8	270.0
2010	217.1	229.9	249.5	231.8	248.4	276.8
2011	218.6	234.2	256.4	234.8	255.0	288.1
2012	219.7	237.6	263.1	236.9	259.8	297.6
2005-2012 Average Annual Growth rates	0.6%	1.6%	2.9%	0.9%	2.0%	3.8%

Source: Gas APR 2004 p 10

Under the medium economic growth scenario, forecast system demand excluding GPG grows at an average rate of 1.6 per cent per annum from 211.8 Petajoule (PJ) in 2005 to 237.6 PJ in 2012. The average annual medium growth rate increases to 2.0 per cent when GPG load is included.

The GPG demand forecasts shown are subject to considerable uncertainty because they are not 'end use' forecasts and are dependent on growth in electricity demand, electricity market conditions and numerous factors including the outcome of competing projects over the next few years.

7 VENCorp, 2004 Gas Annual Planning Review.
8 At the time of writing this report VENCorp is in the process of preparing its 2005 GAPR.
9 Including scheduled gas cogeneration

The forecast 1 in 2 and 1 in 20 peak days are shown in Table 2 for 2005 to 2012. The 1 in 2 peak day forecasts grows from 1,112 TJ in 2005 to 1,243 TJ in 2012 at an average rate of 1.6 per cent per annum. The corresponding 1 in 20 peak day (medium) grows at 1.6 per cent per annum from 1,199 TJ in 2005 to 1,341 TJ in 2012. These forecasts do not include GPG. If GPG is taken into account then the probability of exceedance is considerably higher than 1 in 2 or 1 in 20 years. It should also be noted that over 70 per cent of growth in peak demand is due to the gas heating loads of residential and small industrial and commercial consumers.

Table 2 - Peak demand forecasts (TJ)

	1 in 2			1 in 20			
Calendar Year	**Low**	**Medium**	**High**	**Low**	**Medium**	**High**	**10 August 2005**
2005	1,102	1,112	1,128	1,187	1,199	1,215	1,218
2006	1,108	1,128	1,155	1,196	1,217	1,245	
2007	1,121	1,151	1,190	1,211	1,242	1,283	
2008	1,131	1,167	1,222	1,220	1,259	1,317	
2009	1,138	1,182	1,255	1,229	1,276	1,352	
2010	1,146	1,202	1,288	1,238	1,298	1,388	
2011	1,156	1,224	1,323	1,249	1,332	1,426	
2012	1,164	1,243	1,355	1,258	1,341	1,459	
2005-2012 Average Annual Growth rates	0.8%	1.6%	2.7%	0.8%	1.6%	2.7%	

Source: Gas APR 2004 p 11 Table 2.2

Of note is that on 10 August 2005, the highest ever gas demand of 1,218TJ, which included around 40 TJ of GPG, was recorded on the PTS. This example demonstrates that, taking account of GPG, the 1 in 20 peak day demand level can be exceeded. This was 70 TJ higher than the previous record which occurred on the 28 May 2000. There was a considerable amount of LNG used on the day, 62 TJ, to maintain pressures at the Dandenong City Gate. Given the operating conditions on the day, the system had just enough capacity with the LNG operating at maximum output, without plant redundancy, during the evening to meet demand.

3.2 Supply forecasts

This section provides a high level overview of the supply forecasts for the period 2005 to 2009. More detail can be found in VENCorp's 2004 GAPR.

Table 3 summarises the available and prospective winter peak day gas supplies by injection location as reported by participants for the 2004 GAPR and include firm and non-firm gas supplies.

Table 3 - Forecast supply and storage as reported by participants (TJ)

Injection point	2005	2006	2007	2008	2009
Longford, VicHub and BassGas	1046	1046	1080	1081	1081
Iona	292	352	348	347	345
Culcairn	30	30	30	30	30
Total	**1368**	**1428**	**1458**	**1458**	**1456**

Source: Gas APR 2004 p 19 Table 3.1

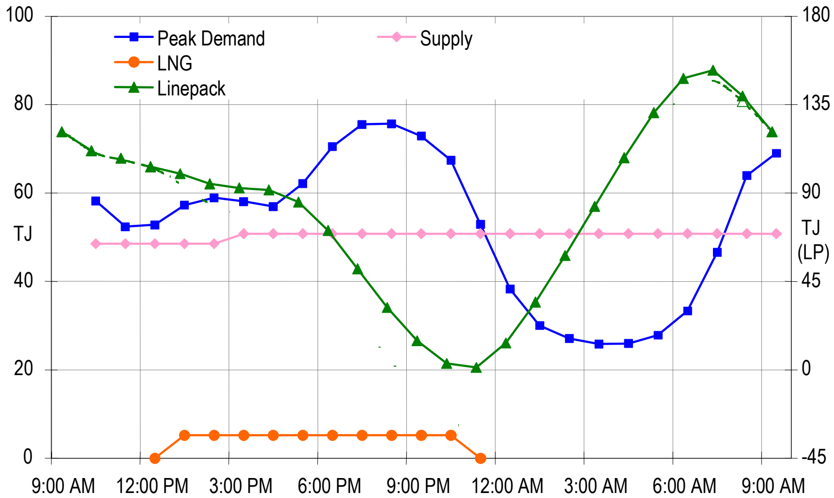
3.3 Peak day supply-demand balance

The available and prospective supplies, outlined in Table 3, exceed 1,300 TJ in 2005 and 1,400 TJ from 2006 onwards and are well in excess of the forecast 1 in 20 peak day demand, of between 1,199 TJ and 1,341 TJ, in the medium scenarios shown in Table 2. Therefore, from a static perspective, there appears to be sufficient supplies to meet the forecast 1 in 20 peak demand.

However, the simple daily supply-demand approach is limited by its inability to consider within day supply-demand balances. The deliverable supply through each major pipeline is constrained by pipeline capacity and available system linepack. For this VENCorp uses a model which is a representation of hourly supply-demand on a gas day. This model treats the gas transmission system as a storage tank holding linepack, which is the quantity of pressurised gas stored or contained in a gas pipeline.

A typical hourly supply-demand profile is represented in Figure 3. The left hand axis applies to supply and demand, while the right axis is for useable system linepack. The amount of useable system linepack varies from day to day depending on operating conditions and demand.

Figure 3 - Within-day supply-demand and useable linepack



Source: Gas APR 2004 p 24 Figure 4.1

Supply typically follows a relatively flat injection profile over 24 hours, whereas demand peaks in the morning and evening and reaches a minimum level overnight. While supply matches demand over 24 hours, linepack in the transmission system varies considerably over the day due to the hourly imbalance between supply and demand. Typically, system linepack falls to a minimum at around 10pm and is rebuilt for the following morning.

Demand varies considerably through the day, increasing in the morning and evening due to gas heating, cooking and hot water loads and decreasing overnight due to shutdown of parts of commerce and industry and reduced heating in homes. Any additional demand from GPG is usually more concentrated in the first half of the gas day and increases this diurnal swing in demand and tends to draw down system linepack. If linepack is depleted, LNG is required to support system pressures. If LNG capacity is insufficient load curtailment would be required.

Due to these within day effects and limited useable linepack, the available and prospective supply quantities outlined in Table 3 cannot transported through the system.

VENCorp has modelled the capacity from each major pipeline and the total system using a calibrated computer model of the PTS.[10]

VENCorp's modelling of major pipelines in the PTS reported in the 2004 GAPR finds that Longford, VicHub and BassGas together are constrained to 1,030 TJ due to back-off effects on the Longford-Melbourne pipeline. The capacity from Iona is constrained to 220 TJ, given current normal winter beginning-of-day operating pressures of the SWP, with response from Iona (as a marginal supply) being limited by the low diameter Corio pipeline (Brooklyn to Lara) bottleneck. Culcairn supply is non-firm and is assumed to provide a further 20 TJ on peak days. In aggregate, total peak day supply from these injections points is 1,270 TJ. However, due to the limited system linepack available for within-day balancing, the total system capacity without recourse to LNG is somewhat lower and is closer to 1,200 TJ, depending on operating conditions.

Because of these system constraints on high demand days, LNG is a critical supply source available directly at the point of demand and serves to meet within-day supply-demand balance if/when useable linepack is depleted. The storage provider reports that LNG can be vaporised at a firm rate of 100 tonnes/hour over 16 hours which equates to 87 TJ. This rate provides redundancy at the LNG plant to manage contingencies such as a more severe demand profile or greater demand than expected, a supply or transmission outage, or an LNG plant unit outage.

In the normal course of events, LNG is not scheduled from the start of the gas day but is included in a reschedule later in the day after demand forecasts and linepack projections are firmed up. Accordingly, the peak day planning assumption based on operational experience is that 60 TJ is available for within-day balancing. The planning assumptions used by VENCorp to assess the adequacy of the system based on a 1 in 20 peak day planning criteria are discussed in detail in Appendix 1.

The 2004 GAPR found that the LNG required exceeds the planning assumption of 60 TJ from 2008 onwards. In the event of a contingency curtailment would be required. These results are summarised in Table 4.

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10 Gregg Engineering Pipeline software is used to model the PTS. See www.greggengineering.com for details on the Gregg Engineering models.

Table 4 - Peak day supply-demand base case (TJ)

Injection point	2005	2006	2007	2008	2009	Capacity limit
1 in 20 Peak Day Demand (medium)	1,199	1,217	1,242	1,259	1,276	
Total scheduled quantity [1]	1,219	1,237	1,262	1,279	1,295	
Longford, VicHub and BassGas	1,030	1,030	1,030	1,030	1,030	1,030
Iona (marginal supply)	128	137	154	165	176	220
Culcairn	20	20	20	20	20	20
LNG	41	50	58	**64**	**69**	**60**
Spare LNG Capacity	46	37	29	23	18	

Source: Gas APR 2004 p 27 Table 4.4

1 Includes 20 TJ to replenish linepack

The 2004 GAPR noted that initial modelling indicated that given the increasing supplies of gas from the Otway basin and the bottleneck caused by the Melbourne-Geelong pipeline a likely option would be an extension of the SWP from Lara to Brooklyn (Corio loop). It also noted that detailed analysis of the costs and benefits of relieving the constraint would be required including the use of a probabilistic planning process if possible. On the basis of the LNG supply assumption of 60 TJ being exceeded in 2008, as shown in Table 4, the 2004 GAPR concluded that system capacity is insufficient and, therefore, a major system augmentation is required by 2008.

4. Options to address emerging network limitation

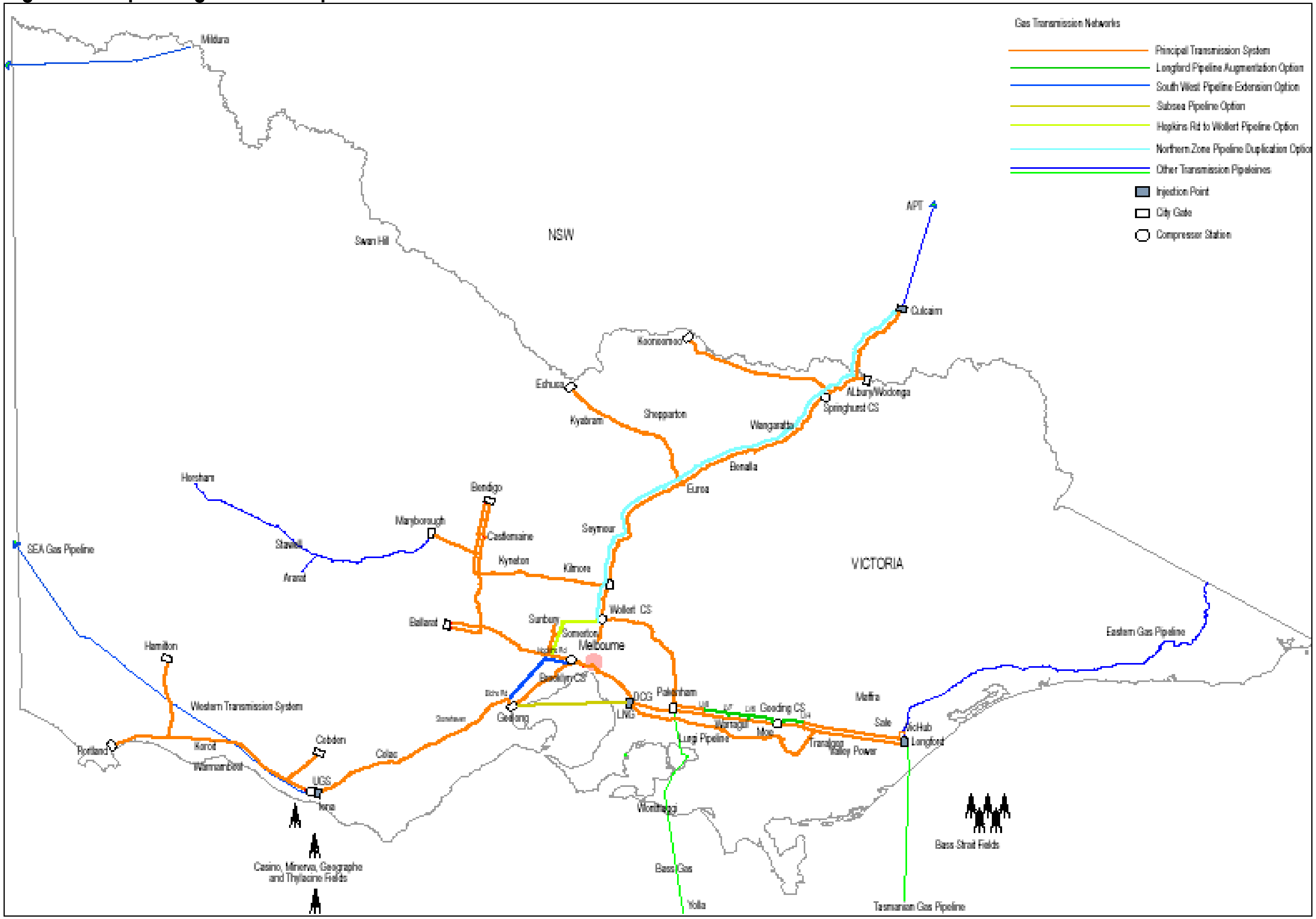
4.1 Introduction

Net benefit assessments require the consideration of options, which are both technically and commercially feasible to address the emerging network limitation. VENCorp has identified the following options, some of which contain a number of variations:

1. Longford pipeline duplication (Longford loop);
2. Corio to Brooklyn augmentation (Corio loop);
3. Corio to Wollert augmentation;
4. LNG facility duplication;
5. Lara to Dandenong Sub-sea Pipeline;
6. Culcairn to Melbourne augmentation; and
7. Stonehaven Compressor Station installation.

Figure 4 below depicts the location of these augmentations in the PTS.

Figure 4 - Map of augmentation options



A summary of the options identified and VENCorp's consideration is set out in Table 5.

Table 5 – Alternative options

	Option		Sub-options	Cost[11]	Proceed to Modelling	Comment
1.	**Longford pipeline duplication**	1a	Two loops 750mm	$34.4 million	**Yes**	Considered to be feasible options
		1b	Three loops 750mm	$55.5 million	**Yes**	
		1c	All four loops 750mm	$73.7 million	**Yes**	
		1d	All four loops + Maximum Operation Pressure Up-Rate existing 750mm pipeline + Gooding Compressors	$119.3 million	No	Options 1a, 1b and 1c considered superior options
2.	**Corio to Brooklyn augmentation**	2a	Lara to Brooklyn 500mm	$67.0 million	No	Options 2b and 2c considered superior
		2b	Elcho Rd to Brooklyn 500mm	$61.7million	**Yes**	Considered to be feasible options
		2c	Elcho Rd to Hopkins Rd 500mm + Hopkins Rd to Brooklyn 600mm	$66.5 million	**Yes**	
		2d	Elcho Rd to Leaks Rd to Brooklyn 500mm	$65.0 million	No	Options 2b and 2c considered superior
3.	**Corio to Wollert augmentation**	3a	Lara to Hopkins Rd + Hopkins Rd to Wollert 500mm	$102.0 million	No	Link to Wollert not considered necessary at this stage and is a natural progression of the Corio option
		3b	Lara to Hopkins Rd 500mm + Hopkins Rd to Wollert 600mm	$109.1 million	No	
4.	**LNG facility duplication**	4a	12,000 tonne plant at Dandenong	$120 million	No	Preliminary modelling indicated security benefits similar to Corio loop but at a substantially greater cost. Further there are no competition benefits from the Otway basin
		4b	12,000 tonne plant in South West Melbourne/Geelong	$130 million	No	
5.	**Lara to Dandenong Sub-sea Pipeline**	5	Lara to Dandenong 750mm	$140 million - $360 million	No	Significant environmental issues and because of route extremely costly
6.	**Culcairn to Melbourne augmentation**	6	Culcairn to Melbourne	$90 million	No	Current utilisation low and existing contracts, depleting Cooper Basin and high costs make it unattractive
7.	**Stonehaven Compressor Station installation**	7	Stonehaven Compressor Station	$30 million	No	Limited benefits at this stage without construction of Corio to Brooklyn augmentation.

Each of these options is discussed in section that follows.

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11 Cost estimates provided by GasNet

4.2 Longford pipeline duplication

There are four unduplicated sections of the Longford pipeline from Tyres to Bunyip. A staged duplication may provide a number of benefits and be a more cost effective solution based on the configuration of the network and utilisation of existing compressor stations.

Option 1a comprises two 750 mm loops of the unduplicated sections. The first section is from Drouin to Bunyip; and the second loop runs from Tyers to Gooding. The total length of the loops is 28 km and is estimated to cost $34.4 million.

Option 1b comprises three 750 mm loops from Drouin to Bunyip, Tyers to Gooding; and Yarragon to Drouin. The total length of the three loops is 47 km and is estimated to cost $55.5 million.

Option 1c comprises four 750 mm loops from Tyers to Bunyip. The total length of the four loops is 62 km and is estimated to cost $73.7 million. It is not expected that there are any significant environmental issues associated with any of these options.

These options are depicted in Attachment 1, Figure 1.

Option 1d is based on Option 1c. The cost of this option is estimated to be $119.3 million. This option looks at building Option 1c and then increasing the operating pressures of the existing Southern loops, installing additional compression at Gooding and making some pipeline modifications at Pakenham and Wollert.

Preliminary analysis shows that the incremental development costs, of around $46 million or more over the other options, is greater than the incremental benefits given that the time frame over which the additional benefits of addressing a future network limitation are likely to arise. As a result VENCorp has only considered Options 1a, 1b and 1c for further assessment.

4.3 Corio to Brooklyn augmentation

Four options have been identified which could serve to increase the capacity of the pipeline between the Brooklyn compressor station and Lara and address the network limitation.

Option 2a is a 500 mm pipeline linking Lara to Brooklyn, a distance of 47 km. This option follows the existing 350 mm pipeline using the existing easements, as far as practicable, with a tie-in to the 500 mm SWP at the Lara city gate. With the construction of the 500 mm pipeline an additional city gate will need to be constructed at Brooklyn.

This option has reasonable certainty with regard to land tenure for the pipeline, given that there are existing easements right through to Lara. There is, however, likely to be strong opposition to the pipeline route from local stakeholders, given the level of urban development along the route. Given the high impact that pipeline construction would have there is a risk that approval for the route may be denied. The main sections of concern are the industrial area from Brooklyn to Fitzgerald Road, the new residential subdivision south of Sayers Road and the commercial development at Hoppers Crossing in the vicinity of Old Geelong Road. The estimated cost to construct this option is $67.0 million. The pipeline loop is relatively expensive to construct, with restricted construction work space within urban areas and the presence of a significant amount of rock contributing to the cost of construction, reinstatement and damages compensation.

The second option, Option 2b, is a 500 mm greenfields pipeline from the SWP at Elcho Road, West Lara, to Hopkins Road, Truganina. It then runs mostly within the existing Brooklyn to Ballan pipeline easement from Hopkins Road to Brooklyn. The pipeline length from West Lara to Brooklyn is 57 km.

Considering the greenfields nature of this option, the urban development and land usage in and around the Brooklyn area, some level of opposition to the pipeline development can be expected. While an Environment Effects Statement is unlikely to be required, a concentrated community consultation program will be necessary. The total cost of this option is estimated at $61.7 million.

Option 2a is shorter than Option 2b however it is considered that stakeholder opposition on Option 2b would be considerably less, thereby giving greater certainty to construction costs and schedules.

Option 2c is identical to Option 2b with the exception of the section running from Hopkins Road to Brooklyn. This section uses 600 mm diameter pipe rather than the 500 mm pipe used in Option 2b. This option should be part of a staged development of a pipeline from Hopkins Road to the Wollert compressor station in the longer term. The additional cost of the pipeline of around $5 million, brings the total cost of the pipeline to $66.5 million.

Option 2d is a 500 mm greenfields pipeline commencing from the SWP at Elcho Road, West Lara, along the same route as Option 2b to Leakes Road, Tarneit, then parallel to Leakes Road to the existing Brooklyn to Lara pipeline at Truganina then within existing pipeline easement to Brooklyn. The pipeline length is 54 km and the estimated cost is $65 million.

Option 2d will encounter strong opposition from stakeholders in the Leakes Road area given the imminent rezoning of the land from rural to residential and industrial. It would also share the level of opposition with Option 2a through the developed industrial area from Fitzgerald Road, Laverton North to Brooklyn.

These options are depicted in Attachment 1, Figure 2.

VENCorp has proceeded to the modelling stage with Option 2b given that it is a lower cost option than Options 2a and 2d and will provide additional linepack benefits.

In addition, VENCorp has proceeded to the modelling stage with Option 2c given that for a small incremental cost it may facilitate future developments on the western side of Melbourne and will provide additional linepack benefits given its length and increased pipe diameter over the other options.

4.4 Corio to Wollert augmentation

The Corio to Wollert option is designed to meet both the short-term network limitation as well as longer-term limitations forecast to arise in the Ballarat area. Two potential options which could address both the existing network requirement and the longer term requirement have been identified.

The first option, Option 3a, is a 500 mm pipeline which follows the same route as Option 2b. That is, it runs from Elcho Road to the start of Hopkins Rd where it connects to the 200 mm Brooklyn to Ballarat pipeline.

Unlike Option 2b, this option does not run into Brooklyn, however, all indicators are that the need to connect back into Brooklyn is required, increasing the cost by $15 million. From Hopkins Road the pipeline uses the existing easement to Sunbury until about 3 km before Diggers Rest where it turns off towards the Wollert Compressor Station.

From Elcho Road to Hopkins Road it is unlikely there would be any significant environmental issues or justified stakeholder concerns. The greenfields section from the Sunbury pipeline easement to Wollert could encounter sustained stakeholder objections due to the urban development through this area. The cost of this option is estimated at $102.0 million.

The second option, Option 3b, uses the same route as Option 3a. However, the section running from Hopkins Road to the Wollert Compressor Station uses 600 mm pipe. The additional costs associated with the 600 mm pipeline development is likely to raise the total cost of this option to around $109.1 million.

These options are depicted in Attachment 1, Figure 3.

In addition to the linepack and capacity benefits these options will also have a transmission deferral benefit. This transmission deferral benefit arises from not having to duplicate the existing 150 mm pipeline from Hopkins Road to Sunbury for 2007, as identified by VENCorp in its 2004 GAPR. Lateral flows on the line to Sunbury have been increasing due to an increase in residential growth from new housing estates and changes in distributor regulation of flows to the local distribution network. The cost of the 12 km duplication in 200 mm is forecast to be around $8.5 million.

The development of an option from Corio to Wollert will indefinitely defer the need for the additional $8.5 million in expenditure.

Despite the immediate additional benefit of these options, the incremental development costs, of around $30 million over the Corio to Brooklyn options, is unlikely to be outweighed by the incremental benefits. This is because the time frame over which the additional benefits of addressing a future network limitation arise are currently beyond VENCorp's forecast horizon. Further this option is best considered as a natural progression of a Corio loop and augmentation is of value if there are greatly increased flows from Iona. As a result VENCorp has not proceeded to the modeling stage with these options.

4.5 LNG facility duplication

A duplication of the existing Dandenong LNG facility has been considered. There is currently provision for the duplication of GasNet's existing LNG facility at Dandenong. However, the facility is now subject to the Major Hazard licensing requirements with WorkSafe Victoria. These requirements are likely to impose additional costs on the duplication of the LNG facility at the current site. Further, there are encroachment issues associated with the current location. As a result of the Major Hazard licensing requirements a facility of a smaller size may be an option or an alternative site would be required. Establishing a new site is likely to present additional environmental problems. The most likely sites are considered to be in the south-west corner of metropolitan Melbourne.

To determine the optimal size of an LNG facility VENCorp has conducted preliminary modelling. LNG modeling requires use of three design variables: storage capacity, vaporisation rates and liquefaction rates.

Given the complexity of LNG modelling, VENCorp has limited its investigations to the medium economic growth scenario in 2008 and 2011.

A LNG facility with a 100 tonnes/hour (5.5 TJ/hour) and a 180 tonnes/hour (9.8 TJ/hour) vaporisation rate were modeled. The results show that, in both cases, a storage capacity of at least 12,000 tonnes is required to meet a 1 in 20 severe winter by 2011 to avoid depletion of the LNG inventory. The higher vaporisation rate of 180 tonnes/hour has significant advantages in reducing curtailment in 2011. To avoid depletion, a liquefaction rate of 150 tonnes/day is required to ensure reasonable replenishment of the tank. Based on these results VENCorp has not modelled a smaller LNG storage facility.

The modelling indicated that the preferred LNG option is one with a storage capacity and vaporisation rate equivalent to the current LNG storage facility at Dandenong. However, the liquefaction rate should be three times as large reflecting much greater use of LNG under this scenario. The estimated capital cost of this option, Option 4a, is around $110 million. Locating a storage facility at an alternative location, Option 4b, would impose additional costs which would raise the cost of the option to around $120 million.

Unlike gas transmission pipelines which have relatively low operating and maintenance costs, of between $20,000 to $180,000 per annum depending on the diameter and length of the pipeline, the costs of vaporisation and liquefaction are significant. These costs are estimated to be around $1 million per year based on average levels of modeled LNG use. Given the construction cost of $110 million and the operating costs of around $1 million per annum the total NPV of the costs of these options would be around $120 million and $130 million respectively. In addition, the LNG facility is likely to have zero or negative competition benefits as it is likely to increase the average cost of gas given that it will be offered into the market at higher prices than gas offered from the basins.

While this LNG option would be likely to provide significant benefits to the market, commensurate with those provided by a Corio to Brooklyn augmentation, the cost of constructing and operating an LNG facility are close to double those of the construction of new pipelines. As a result of the estimated high costs VENCorp has not proceeded to the detailed modeling stage with these options.

4.6 Lara to Dandenong Sub-sea pipeline

The Lara to Dandenong option consists of a 750 mm Sub-sea pipeline across Port Phillip Bay. The route would entail 24 km of transmission pipe on land and around 46 km under Port Phillip Bay. The most likely route for the Sub-sea component would be from the southern end of Lake Borrie across to Mordialloc. Sub-sea pipelines are required to be buried at a reasonable depth or in some cases along the seabed and encased in concrete.

The expected range of costs for this option are between $140 million and $360 million and it is likely to encounter significant environmental opposition. As a result of the likely costs and environmental issues VENCorp has not proceeded any further with its consideration of this option.

4.7 Culcairn to Melbourne augmentation

Duplicating an augmentation of the existing pipeline from Culcairn to Melbourne will provide greater access to supplies from the Cooper Basin as well as potentially the Papua New Guinea fields in the longer term. However, depleting Cooper Basin reserves, current low utilisation of the existing capacity on the pipeline, the limited contracts entered into between producers and retailers, and a potential cost of $90 million, this option is not considered feasible at this stage.

4.8 Stonehaven Compressor Station installation

The Stonehaven Compressor Station is to be located south-west of Geelong on the SWP. In its 2004 GAPR, VENCorp identified a possible need for the installation of compression on the SWP near Stonehaven by around 2012 after the duplication of the Corio to Brooklyn pipeline. Modelling at the time indicated that the compressor station would increase the capacity into Melbourne by up to 115 TJ with an augmentation between Corio and Brooklyn but by just 20 TJ without an augmentation between Corio and Brooklyn.

As a result of this modelling, VENCorp considers that the installation of a compressor station at Stonehaven should be part of a staged development of any augmentations to the South-West of Melbourne and would logically follow after a Corio to Brooklyn augmentation. Consequently, VENCorp has not pursued this option any further.

5. Technical analysis

The previous section identified a range of options, which were considered technically feasible to address the network limitation. A number of options were eliminated on the grounds that they were not considered commercially feasible options, such as the Sub-sea pipeline or the Culcairn to Melbourne augmentation. Others were dismissed on the grounds that they are better considered as the second stage of another augmentation, such as the Stonehaven Compressor Station and Corio to Wollert augmentation. Of those identified five options, or variations to options, were considered suitable for further investigation.

5.1 Modelling and supply assumptions

VENCorp has conducted detailed technical analyses of each of these options using a calibrated computer model of the PTS.[12] The modeling involves use of standard peak day demand profiles and projected linepack targets amounts and other operating conditions. The model requires assumptions on the length of the pipeline, the diameter of the pipes; the location of the augmentation; likely future injections and the location of those injections and system pressures. It provides detailed information on the additional capacity and linepack of each of the augmentations modelled.

A number of key supply assumptions have been made in this analysis. The firm supply Maximum Daily Quantity (MDQ) available from the Longford pipeline is no more than 1,030 TJ reflecting information provided for the GAPR. This assumption is considered conservative in that firm supply MDQ from the Gippsland Basin is declining. In contrast, firm supply MDQ available from Iona already exceeds 300 TJ and will increase with new Otway developments scheduled for 2006/07.

5.2 System capacity

5.2.1 Longford loop options

VENCorp's modelling indicates that Option 1a, the Longford two loop option, would add around 26 TJ/day of extra capacity to the current system over a 24 hour period. Adding the third loop, Option 1b, provides another 15 TJ/day to the system capacity, increasing the cumulative benefit to around 41 TJ/day. All four loops provide an additional 14 TJ/day over the three loop option bringing the capacity of the four loops to 55 TJ/day.

5.2.2 Corio loop options

Option 2b, from Elcho Road to Brooklyn 500 mm pipeline, increases the SWP delivery over 24 hours by 87 TJ. Increasing the diameter of the SWP extension from Hopkins Road to Brooklyn from 500 mm to 600 mm, Option 2c, adds an additional 5 TJ/day of capacity to the SWP capacity bringing the total increase in the system capacity to 92 TJ/day.

The increase in system capacity is summarised in Table 6.

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12 VENCorp uses Gregg Engineering software.

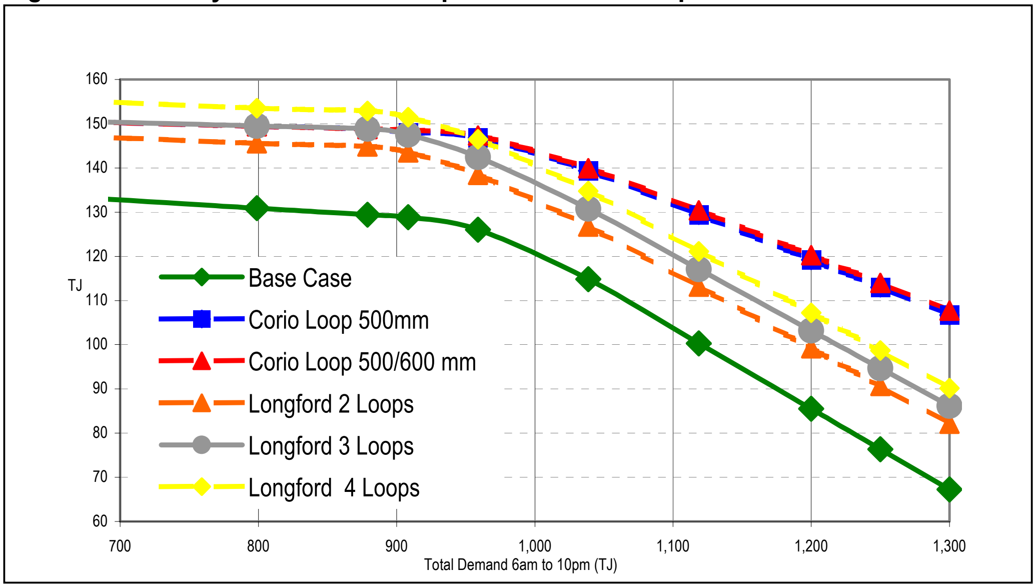
Table 6 - Modelled increases in maximum system capacity

Option		Increase in Capacity (TJ/day)
Longford 2 loops	1a	26
Longford 3 loops	1b	41
Longford 4 loops	1c	55
Corio loop 500mm	2b	87
Corio loop 500/600mm	2c	92

5.3 System linepack

System capacity is highly dependent on useable linepack to meet supply-demand imbalances within a day, particularly throughout the evening peak demand period to 10 pm. Useable linepack has been modelled and is dependent on system demand as depicted in Figure 5.

Figure 5 - Total System Useable linepack with various options



It is apparent from Figure 4 that the Corio loop options provide significantly more useable linepack at higher demands. This is largely due to the Corio loop enabling better utilisation of the linepack already existing in the SWP.

5.3.1 Longford loops

Option 1a, the two Longford loop option, adds around 11 TJ of additional useable linepack, while the three loop option, Option 1b, adds around 20 TJ. All 4 Longford loops, Option 1c, adds just over 20 TJ of linepack. Of the Longford options, Options 1c provides the greatest increase in system capacity and useable linepack, however, it introduces operational problems arising from lower pressures at Longford.

VENCorp has conducted preliminary economic comparisons of Option 1b and Option 1c by comparing the medium economic growth scenario benefits in 2008 and 2011. While Option 1c was found to deliver marginally higher benefits than Option 1b it comes at a cost of around $18 million. On this basis, VENCorp has proceeded with more detailed economic modelling of Option 1b which is the preferred Longford loop option.

5.3.2 Corio loops

The 500 mm extension of the SWP from Elcho Road to Brooklyn, Option 2b, provides an increase in useable system linepack of between 20 TJ and 40 TJ depending on system demand while Option 2c, the replacement of the 500 mm pipe from Hopkins Road to Brooklyn with 600 mm pipe adds an additional 1 TJ.

Currently, regardless of the start-off-day operating pressures at Iona, useable linepack in the SWP is limited to about 20 TJ due to the effects of Lara to Brooklyn bottleneck. The Corio loop option provides a very significant additional system benefit by freeing up 15 TJ to 20 TJ of existing SWP linepack for within-day balancing by allowing gas flows to by-pass the bottleneck.

As with the Longford options, VENCorp conducted preliminary economic assessments of the benefits in 2008 and 2011 based on the medium economic growth scenario. Option 2c provides additional capacity and useable linepack benefits over Option 2b. However, the estimated additional cost of the 600 mm pipeline of around $5 million means that it is unlikely that the market benefits and cost-benefit ratio of Option 2b will be superior to Option 2c.

Based on these findings VENCorp has considers that Option 2b is the preferred Corio loop option.

6. Benefits of addressing the network limitation

6.1 Market benefits

6.1.1 Calculating market benefits

VENCorp has limited its assessment of benefits to those that are quantifiable from a financial perspective and can be attributable to those parties which produce, consume and transport gas in Victoria's PTS. From this perspective the analysis is akin to a partial equilibrium analysis. That is, the analysis of relationships within a particular sub-sector of an economy. VENCorp has deliberately avoided quantifying the flow on effects of benefits to other sectors outside the PTS associated with a general equilibrium assessment. VENCorp has also avoided quantifying benefits which would be considered externalities and are not readily quantifiable.

VENCorp considers that there are three primary benefits arising from a new augmentation to the PTS:

- Reductions in involuntary load curtailment arising from network inadequacy (within day constraints);
- Reductions in involuntary load curtailments arising from supply outages (of varying durations); and
- Competition benefits.

Each of these benefits is discussed in turn.

6.1.2 Reductions in involuntary load curtailment (network)

The involuntary curtailment of load will principally arise for one of two reasons, because there is inadequate network with which to deliver gas (i.e. there is sufficient supply to meet the demand but insufficient network along which to transport the gas) or because of inadequate supply to meet demand due to a plant or pipeline failure (i.e. there is sufficient network capacity to transport the gas but insufficient gas supply to meet demand.) These benefits are calculated by multiplying the probability of an event occurring and the magnitude of that event by the value that customers place on the loss of supply.

The frequency and magnitude of involuntary curtailment arising from inadequate network capability has been determined using VENCorp's mass balance model. [13] As noted in section 5, the mass-balance model uses a representation of the hourly supply-demand on a gas day. The modeling essentially involves taking the beginning of day line pack level and, given forecast and actual supply and demand, scheduled curtailment and LNG injections so as to meet end of day linepack targets. The model provides daily curtailment amounts and LNG injections over the forecast planning horizon. The results of VENCorp's analysis, which compares the reductions in curtailment with the Longford and Corio augmentations with the no augmentation case, is presented in Tables 7 and 8.

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13 A more detailed description of VENCorp's mass balance model is set out in Appendix 2.

Table 7 - Reduction in involuntary curtailment (network) Longford loop

Year	Low economic growth scenario		Medium economic growth scenario		High economic growth scenario	
	GPG Curtailment (TJ)	Industrial and Residential Curtailment (TJ)	GPG Curtailment (TJ)	Industrial and Residential Curtailment (TJ)	GPG Curtailment (TJ)	Industrial and Residential Curtailment (TJ)
2007	3.8	3.1	8.0	8.6	24.5	15.8
2008	6.4	4.6	12.5	11.5	72.2	31.6
2009	8.3	6.7	21.5	14.7	165.3	55.5
2010	9.2	9.0	38.7	20.0	316.8	99.8
2011	12.9	12.3	74.5	34.1	530.5	171.6

Table 8 - Reduction in involuntary curtailment (network) Corio loop

Year	Low economic growth scenario		Medium economic growth scenario		High economic growth scenario	
	GPG Curtailment (TJ)	Industrial and Residential Curtailment (TJ)	GPG Curtailment (TJ)	Industrial and Residential Curtailment (TJ)	GPG Curtailment (TJ)	Industrial and Residential Curtailment (TJ)
2007	5.4	4.1	10.2	11.0	33.8	24.7
2008	7.9	6.3	16.4	15.1	99.9	43.8
2009	10.6	8.4	28.5	21.4	243.5	79.1
2010	12.4	10.7	53.2	29.8	482.3	146.3
2011	17.6	14.4	103.4	46.3	878.1	257.9

6.1.3 Reductions in involuntary load curtailment (supply failure)

In terms of the probability of curtailment due to a supply failure VENCorp has based its assessment on a study undertaken by Charles River Associates (CRA) for VENCorp in 2002[14]. VENCorp commissioned the review for the purposes of establishing a minimum reserve for the LNG facility assuming a single event analysis and a set of contingency scenarios. However, the events identified by CRA are equally applicable for use in the context of quantifying the market benefits of a supply point failure. In its study CRA identified and determined probabilities for the occurrence of the following failures:

14 Charles River Associates, Victorian Gas Systems Security Cost-Benefit Risk Analysis, March 2002.

- A minor, within day, supply failure resulting in some curtailment;
- A major, full day, supply failure requiring the gas system to be partially shutdown resulting in substantial curtailment;
- An extended supply failure, of one week duration, requiring the gas system to be completely shut down resulting in significant curtailment; and
- Other including a pipeline failure and force majeure event of around two days duration.

The (discrete) probability of these events occurring and the expected reduction in curtailment arising from the augmentation is outlined in Table 9.

Table 9 - Reduction in involuntary curtailment (supply) Longford and Corio loops

Event type	Probability of Occurrence (Probability 1 in N years)	Assumed Duration of Event (days)	Reduction in Industrial and Residential Curtailment (TJ) [1]	
			Corio loop	Longford loop
Gas Supply Failure – minor	6[2]	1/3	29.6	14.3
Gas Supply Failure – major	30	1	84.7	27.9
Gas Supply Failure – extended	50	7	592.9	27.9
Pipeline failure	100	2	169.4	27.9
Force Majeure Events	100	2	169.4	27.9

1 The reduction in industrial and residential curtailment also includes an insignificant amount of GPG curtailment.
2 VENCorp has deviated from CRA's estimated probability of occurrence for a minor event of 1 in 3 years. CRA's probability is applied to usage of LNG to manage system security events. Analysis of system incidents show that unlike the major and extended failures, in about half of such events the LNG will be sufficient to manage the event without recourse to curtailment.

6.1.4 Calculating reduction in involuntary load curtailment benefits

VENCorp has assessed the system security benefits of each augmentation in terms of the value of the relative curtailment that could be expected given a serious supply production outage or pipeline outage from either the Longford side or the Iona side. VENCorp's analysis show that either augmentation will serve to deliver additional gas and provide additional linepack that would reduce the level of curtailment relative to the base case. However, given the assumption that total Longford pipeline supply MDQ available is limited to 1,030 TJ due to contractual supply arrangements and production capacity, based on advice received for the GAPR, the increase in benefits of the Longford loop option are limited to the first day in the event of an Iona or SWP outage. On the other hand, the reduction in curtailment due to the Corio loop can be directly related to the increase in supply capacity from Iona to Melbourne.

Modelling of the same scenarios used for the market benefits analysis indicates that the reduction in curtailment essentially applies to the industrial sector. Further, the relative benefits are, to a very good approximation, the same in each year, because the difference in curtailment relates directly to the increase in capacity due to the augmentation.

To evaluate the relative benefits, the frequency and magnitude of both the supply and network curtailment events is multiplied by the value of gas curtailment to consumers, generally known as the Value of Customer

Reliability (VCR). The calculations used to calculate the Value of Unserved Energy (VUE) for both can be expressed as follows:

Reduction in VUE (network) = $\{[\,Pr(_{LC}) \times LC_{\text{(without augmentation)}}\,] - [\,Pr(_{LC}) \times LC_{\text{(with augmentation)}}\,]\} \times VCR$

And

Reduction in VUE (supply) = $Pr(_{LC}) \times RLC \times VCR$

Where

$Pr(_{LC})$ Probability of Load Curtailment
LC Load Curtailed (in Gigajoule (GJ))
VCR Value of Customer Reliability ($/GJ)
RLC Reduction in Load Curtailment

6.1.5 Value of Customer Reliability

During 2005 VENCorp retained consultants to undertake a survey of large gas end users to determine the applicable VCR for the customer sectors which are likely to be curtailed first in the event of serious network constraints or gas supply outages.[15] VENCorp ensured that the survey design and VCR calculation methodology was sound and was consistent with the market modelling approaches undertaken in this study. A high response rate was achieved and VENCorp believes that the VCR results are robust.

The VCR for large industrials was determined for a period of 8 hours (within day), 24 hours, and 7 days as summarised in Table 10. The VCR for large industrial customers for curtailment of around 8 hours due to within day network supply constraints was found to be $185/GJ. The VCR was lower for longer periods of gas curtailment reducing to $105/GJ for 24 hours and $68/GJ for extended outages of a week. The VCR is higher for shorter periods due to similar fixed cost components applying to all time periods.

Table 10 - Value of customer reliability

Duration of Interruption	VCR ($/GJ)
8 hours	$185
24 hours	$105
7 days	$68
GPG	$ 0 to $28

The VCR for GPG who have backup distillate was found to be in the range $0/GJ to $28/GJ depending on the average National Electricity Market (NEM) price during the period of gas curtailment. The upper bound of $28/GJ represent the additional costs of switching to distillate when NEM prices are very high, greater than $300/MWh. VENCorp analysed NEM prices on the 10 days of highest gas demand from 2000 to 2004 and found that a VCR of $10/GJ represented the reduction in profit /GJ on these days and has used this value in its base case.

15 McLennan, Magasanik and Associates, The Value of Customer Reliability for Gas, 20 September 2005. This report is available from VENCorp's website.

Tables 11 and 12 present the VUE benefits (network) for the Longford loop (Option 1b) and Corio loop (Option 2b) options under the high, medium and low economic growth scenarios. Given the time taken to construct either or these two pipelines VENCorp has undertaken modelling from 2007 onwards. From 2011 onwards, the benefits are assumed to remain the same as 2011 benefits. This is considered to be a conservative assumption given that the modelling shows that the benefits continue to grow according to a quadratic function.

The reduction in the VUE (network) is calculated from an expected value in the base case by, weighting both the low and high economic growth scenarios by 1/6 and the medium economic growth scenario by 2/3.

Table 11 - Reduction in value of unserved energy (network)

	Longford loop (Option 1b) ($2005 million)				
	2007	**2008**	**2009**	**2010**	**2011**
Medium Economic Growth	1.7	2.3	2.9	4.1	7.1
Low Economic Growth	0.6	0.9	1.3	1.8	2.4
High Economic Growth	3.2	6.6	11.9	21.6	37.1
Probability Weighted	**1.7**	**2.8**	**4.2**	**6.6**	**11.3**

Table 12 - Reduction in value of unserved energy (network)

	Corio loop (Option 2b) ($2005 million)				
	2007	**2008**	**2009**	**2010**	**2011**
Medium Economic Growth	2.1	3.0	4.2	6.1	9.6
Low Economic Growth	0.8	1.3	1.7	2.1	2.8
High Economic Growth	4.9	9.1	17.1	31.9	56.5
Probability Weighted	**2.4**	**3.7**	**6.0**	**9.7**	**16.3**

The VUE associated with supply events is set out in Tables 13 and 14.

Table 13 - Reduction in value of unserved energy (supply)

	Longford loop (Option 1b) ($2005 million)				
	2007	**2008**	**2009**	**2010**	**2011**
Total	0.4	0.4	0.4	0.4	0.4

Table 14 - Reduction in value of unserved energy (supply))

	Corio loop (Option 2b) ($2005 million)				
	2007	**2008**	**2009**	**2010**	**2011**
Total	1.9	1.9	1.9	1.9	1.9

The accumulated benefits of the Longford loop and Corio loop options are set out in Tables 15 and 16.

Table 15 - Market benefits

	Longford loop (Option 1b) ($2005 million)				
	2007	**2008**	**2009**	**2010**	**2011**
Involuntary Curtailment (network)	1.7	2.8	4.2	6.6	11.3
Involuntary Curtailment (supply)	0.4	0.4	0.4	0.4	0.4
Total	**2.2**	**3.2**	**4.7**	**7.1**	**11.8**

Table 16 - Market benefits

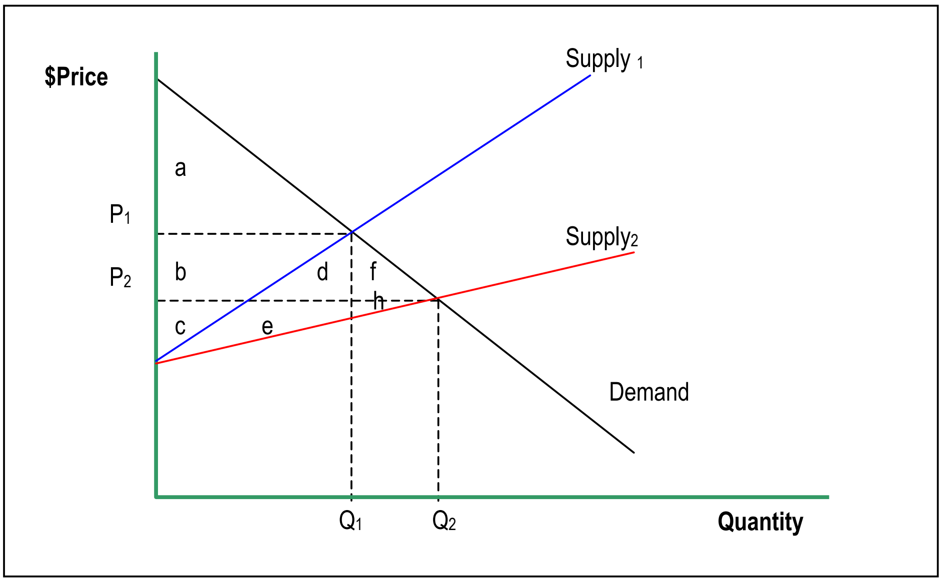
	Corio loop (Option 2b) ($2005 million)				
	2007	**2008**	**2009**	**2010**	**2011**
Involuntary Curtailment (network)	2.4	3.7	6.0	9.7	16.3
Involuntary Curtailment (supply)	1.9	1.9	1.9	1.9	1.9
Total	**4.3**	**5.6**	**7.9**	**11.6**	**18.2**

6.1.5 Competition benefits

VENCorp has defined competition benefits to be the increase in economic welfare (i.e. the increase in consumer and producer surpluses) arising from additional inter and intra-basin competition that results from a network expansion. In other words it is the benefits of greater competition between gas suppliers.

Graphically, it can best be described with reference to the simple diagram below. Assume initially that the market supply curve is given by S1. The market-clearing price and quantity will be given by the intersection of supply and demand, P1 and Q1 respectively. Demand is assumed to be elastic. After an augmentation is constructed, competition between gas supplies will increase, reducing the price at which the gas is supplied, thereby resulting in a shift of the supply curve from S1 to S2.

Figure 6 - Competition benefits



The change in social welfare is defined with reference to the increase in consumer and producer surpluses. Consumer surplus is traditionally defined as the difference between a consumer's maximum willingness to pay for a unit of good and the price that he or she actually pays for that good. In the case above, it is given by the area above the price P1 and is bound by the demand curve, represented by the triangle a. Producer surplus is defined as the difference between the generator's total revenue and opportunity cost of production. In other words, it is the area above the supply curve and bounded by the price P1 and is given by b + c.

A network augmentation will shift the supply curve to the right (i.e. from $Supply_1$ to $Supply_2$). The effect will be an increase in social welfare which can be calculated using the following formula:

$$\mathbf{\Delta\ SW} = \mathbf{\Delta\ CS} + \mathbf{\Delta\ PS}$$

The increase in consumer surplus is given as follows:

$$\mathbf{\Delta\ CS} = b + d + f$$

The increase in producer surplus is given as follows:

$$\mathbf{\Delta\ PS} = - b + e + h$$

Therefore, the increase in social welfare is simply:

$$\mathbf{\Delta\ SW} = b + d + f +(- b + e + h) = d + e + f + h$$

Calculating competition benefits requires assumptions to be made about a number of factors including:

- Bidding behaviour for existing and new gas suppliers;
- Contract positions of gas suppliers and customers; and
- Elasticity of demand.

VENCorp has estimated the competition benefits using the projected 'uplift' derived from its mass balance model and an assumed bidstack.[16] As this method incorporates both wealth transfers and efficiency gains VENCorp has only included the competition benefits in its sensitivity testing and not in its base case modelling. VENCorp's belief is that the efficiency benefits are likely to be in the order of $200,000 to $300,000 per annum, but these cannot be quantified at this stage. VENCorp considers that it is being conservative by not including these benefits in the base case.

Tables 17 and 18 set out the competition benefits calculations.

Table 17 - Competition benefits

	Longford loop (Option 1b) ($2005 million)				
	2007	**2008**	**2009**	**2010**	**2011**
Total	0.9	1.2	1.5	1.9	2.3

16 Uplift is a charge imposed on Market Participants based on a daily allocation, made in accordance with the Market and System Operation Rules (MSOR), of the total ancillary payments payable in respect of that day. Ancillary payments are additional payments made to Market Participants to compensate when transmission constraints or surprises result in them being disadvantaged by a uniform, daily Market Price, The bidstack used was based on the 2005 peak days on Aug 10 and 11.

Table 18 - Competition Benefits

	Corio loop (Option 2b) ($2005 million)				
	2007	2008	2009	2010	2011
Total	1.0	1.4	1.7	2.2	2.7

6.2 Net Market Benefits

VENCorp has aimed to maintain consistency in the key variables used to calculate the net market benefits of the options as those used in its electricity regulatory test assessments. However, it has deviated from the approach set out in the regulatory test in two respects. First, in addition to identifying which option maximises the net market benefits, which is the test set out in the electricity regulatory test, VENCorp will also consider the NPV cost-benefit ratio of the two options. It is not uncommon for higher cost projects to have higher economic benefits. However, on a dollar for dollar basis the lower cost option can prove to provide greater benefits. Therefore, VENCorp considers it prudent to have regard to which project maximises the net market benefit as well as which project has the higher cost-benefit ratio. Further, VENCorp will account for risk and uncertainty of factors, such as the timing of future augmentations, by setting a cut-off period in which the cost and benefits are assessed and using a higher discount rate for benefits after that period.

The key input variables adopted in the base case are set out in Table 19.

Table 19- Base case assumptions

Assumption	Base Case
VCR for GPG	$10/GJ
VCR for large industrial consumers	$185/GJ
Weightings	1/6 low, 2/3 medium, 1/6 high
Modelling	To 2011
Competition Benefits	Not Included
Economic Life of Project	50 years
Discount Rate	7% to 2011 10% beyond 2011

The results of the analysis are contained in tables 20, 21 and 22.

Table 20 - Net market benefits (NPV)

Option	($2005)
Longford loop	47.2million
Corio loop	93.1million

Table 21- Cost-benefit ratio

Option	Cost-benefit ratio
Longford loop	2.1
Corio loop	2.9

Table 22 - Optimal timing

Option	Optimal timing
Longford loop	2009
Corio loop	2008

As is evident, the Corio loop option satisfies both tests in that it maximises the net market benefit and has a higher cost-benefit ratio than the Longford loop.

Economic cost-benefit assessments typically encompass sensitivity testing on key input variables to assess how robust the results are. VENCorp has conducted sensitivity testing on the following:

Table 23 - Sensitivity testing assumptions

Assumption	Base Case	Sensitivity Test
VCR for GPG	$10/GJ	$28/GJ
VCR for large industrial consumers	$185/GJ	+ 25% - 25%
Weightings	1/6 low, 2/3 medium, 1/6 high	20% low, 60% medium, 20% high 0% low, 100% medium, 0% high 10% low, 80% medium, 10% high
Modelling	To 2011	To 2012
Costs	$55.5 million (Longford loop) $61.7 million (Corio loop)	+ 25% - 25%
Competition Benefits	Not Included	Included
Economic Life of Project	50 years	40 years 60 years
Discount Rate	7% to 2011 10% beyond 2011(for benefits)	6% to 2011 and 10% beyond 2011 (for benefits) 8% to 2011 and 10% beyond 2011 (for benefits)

The results of these sensitivity tests setting out the net market benefits, the cost-benefit ratio and optimal timing are contained in Table 24.

Table 24 - Results of sensitivity testing

	Longford loop			Corio loop		
	Net Market Benefits (NPV $2005 million)	**Cost-Benefit Ratio**	**Optimal Timing**	**Net Market Benefits (NPV $2005 million)**	**Cost-Benefit Ratio**	**Optimal Timing**
Base Case	**47.2**	**2.1**	**2009**	**93.1**	**2.9**	**2008**
VCR $28 for GPG	66.3	2.6	2009	122.9	3.4	2008
25% reduction in VCR	28.6	1.7	2010	65.6	2.3	2008
25% increase in VCR	66.0	2.5	2009	120.9	3.2	2008
Weighting 20% / 60% / 20%	53.7	2.3	2009	103.2	3.1	2008
Weighting 0% / 100% / 0%	15.7	1.4	2010	42.2	1.9	2008
Weighting 10% / 80% / 10%	34.5	1.8	2009	106.4	3.1	2008
25% reduction in costs	58.1	2.7	2008	106.5	3.6	2007
25% increase in costs	36.8	1.8	2010	80.4	2.4	2009
6% discount rate	52.4	2.2	2009	102.5	2.9	2008
8% discount rate	42.6	2.1	2009	84.7	2.7	2008
Asset life 40 years	45.6	2.1	2009	82.0	2.7	2008
Asset life 60 years	47.9	2.1	2009	94.1	2.9	2008
Competition Benefits	73.1	2.7	2008	120.0	3.2	2007
Modelling 2012	77.6	2.8	2009	141.9	3.8	2008

VENCorp's sensitivity testing shows that in all cases the Corio loop has both a considerably higher net market benefit at a better cost-benefit ratio compared to the Longford loop. For the Corio loop eleven out of the fourteen sensitivity tests show that it is optimal for the project to be installed for 2008, with two suggesting 2007 and one indicating 2009. For the Longford loop nine out of the fourteen sensitivity tests show that the optimal timing for the project is 2009, with three indicating 2010 and two suggesting 2008.

Based on these results, the Corio loop maximises the benefit to the market if it is operational for May 2008. However, sufficient contingency must be provided in the construction of the project to allow for any unforeseen events. Comparing the cost of missing winter 2008 through an unexpected delay, of $5.6 million, and the probability of missing the target completion date, around 1/3 based on VENCorp's experience in the electricity sector, with the cost of financing the project for an earlier completion date, of around $1 million, suggests that targeting an earlier completion date would be appropriate.

For this reason VENCorp supports the completion of the project by 1 March 2008.

7. Conclusion

This report presents a detailed cost-benefit analysis of options to address an emerging network limitation which was identified in VENCorp's 2004 GAPR as being required before winter 2008.

VENCorp identified a number of options in its assessment. Following a preliminary cost-benefit assessment two options were considered suitable for detailed technical and economic analysis: the Longford loop and the Corio loop.

The results of VENCorp's modelling indicates that despite the higher cost of a pipeline from Lara to Brooklyn the Corio loop has greater net market benefits, $93.1 million compared with $47.2 million, at a higher cost-benefit ratio than the Longford loop, 2.9 compared with 2.1.

These higher benefits are primarily due to the increased system capacity and linepack arising from better utilisation of linepack already existing in the SWP freeing up of the bottleneck from Geelong to Melbourne. The Corio loop also provides greater access to the significant developments of new gas supplies in the Otway Basin which increases system security. As a result, VENCorp considers that it is the most suitable option to address the emerging network limitation.

The Corio loop maximises the benefit to the market if it is operational for May 2008. However, sufficient contingency must be provided in the construction of the project to allow for any unforeseen events. For this reason VENCorp supports the completion of the project by 1 March 2008.

Appendix 1 1 in 20 peak day gas planning standard

VENCorp adopts a 1 in 20 peak day planning standard for the Gas Market. When conducting its assessment VENCorp adopts a 65 per cent demand profile with forecast error and Beginning of Day (BoD) linepack deficit of up to 20 Terajoules (TJ) under target to assess its 1 in 20 planning standard. VENCorp also assumes a forecast error of 7.3 per cent below actual demand. Using this planning standard any day which requires greater than 60 TJs of Liquefied Natural Gas (LNG) leaves no security margin and no redundancy in the LNG facility for at least part of the day. Under these circumstances it is very likely that an emergency would be declared and curtailment would follow. Given demand forecast error, scheduling of 60 TJ of LNG at the firm rate requires LNG to be vaporised from 11:30am to 10:30pm to be effective.

The assumptions used by VENCorp to assess the adequacy of the system based on a 1 in 20 peak day planning criteria are summarised in Table A1 below.

Table A1 Planning assumption base case and sensitivities

Assumption	Base Case	Sensitivity Test
System demand	1 in 20 peak day	1 in 2 peak day with GPG comparable to a 1 in 20 level without GPG
System demand profile (% of daily demand 9 am to 10 pm)	65%	64% 66%
Forecasting error	7.3% under actual demand:	no forecasting error
BoD linepack	-20 TJ below target	-40 TJ below target on target

Based on the supply-demand assumptions identified by VENCorp in its 2004 GAPR, and set out in Chapter 4 of this supporting submission, Table A2 shows that network limitations are likely to emerge from 2008 under the base case assumptions.

As is evident, the LNG requirements increase markedly with severity of demand profile or if available useable linepack is reduced further due to increased demand prior to 9am for example due to a colder morning than expected or due to higher GPG than forecast.

Table A2 - LNG requirement for 1 in 20 peak day

Profile	FC Error	ΔBoD LP	2005	2006	2007	2008	2009
64.0%	N	0	0	1	6	9	14
64.0%	Y	0	7	13	21	27	32
64.0%	N	-20	6	11	21	27	34
65.0%	N	0	9	17	28	35	42
64.0%	Y	-20	21	29	37	42	48
65.0%	Y	0	26	34	43	48	54
64.0%	N	-40	21	31	41	47	54
65.0%	N	-20	27	37	48	55	62
64.0%	Y	-40	37	44	53	58	63
66.0%	N	0	33	44	55	62	70
65.0%	**Y**	**-20**	**41**	**50**	**58**	**64**	**69**
66.0%	Y	0	46	55	64	70	76
65.0%	N	-40	47	57	68	75	82
65.0%	Y	-40	57	65	74	79	85
66.0%	N	-20	53	64	75	82	90
66.0%	Y	-20	62	70	79	85	91
66.0%	Y	-40	77	86	95	101	107
66.0%	N	-40	73	84	95	102	109

In Table A2, a colour code is used to represent the level of LNG required. Green indicates a requirement for 0 to 40 TJ; Amber for 41 to 60 TJ; and red/orange more than 60 TJ. The red/orange areas identify scenarios where system capacity is inadequate to meet demand.

The same variations were also applied to the scenarios where the 1 in 20 level of demand was replaced by 1 in 2 peak day system demand with GPG. These cases involve more severe demand profiles and, in the case of GPG, increased forecast error. These results are highlighted in Table A3. Under these assumptions it shows that by 2007, the combination of useable system linepack and LNG capacity is insufficient to meet 1 in 2 peak day demand

Table A3 - LNG Requirement for 1 in 2 peak day with GPG

Profile	FC Error	Δ BoD LP	2005	2006	2007	2008	2009
64.0%	N	0	0	1	6	9	14
64.0%	N	-20	6	10	21	28	34
65.0%	N	0	7	15	26	33	40
64.0%	Y	0	13	22	31	36	42
64.0%	N	-40	20	30	41	48	54
64.0%	Y	-20	28	37	46	52	58
65.0%	N	-20	25	35	46	53	60
66.0%	N	0	29	40	51	58	66
65.0%	Y	0	31	40	50	56	62
64.0%	Y	-40	43	52	61	67	73
65.0%	**Y**	**-20**	**47**	**56**	**65**	**71**	**77**
65.0%	N	-40	45	55	66	73	80
66.0%	Y	0	50	59	69	75	82
66.0%	N	-20	49	60	71	78	86
65.0%	Y	-40	62	71	80	87	93
66.0%	Y	-20	65	75	84	91	97
66.0%	N	-40	69	79	91	98	106
66.0%	Y	-40	81	90	100	106	112

Under this scenario, there is a capacity shortfall in 2007.

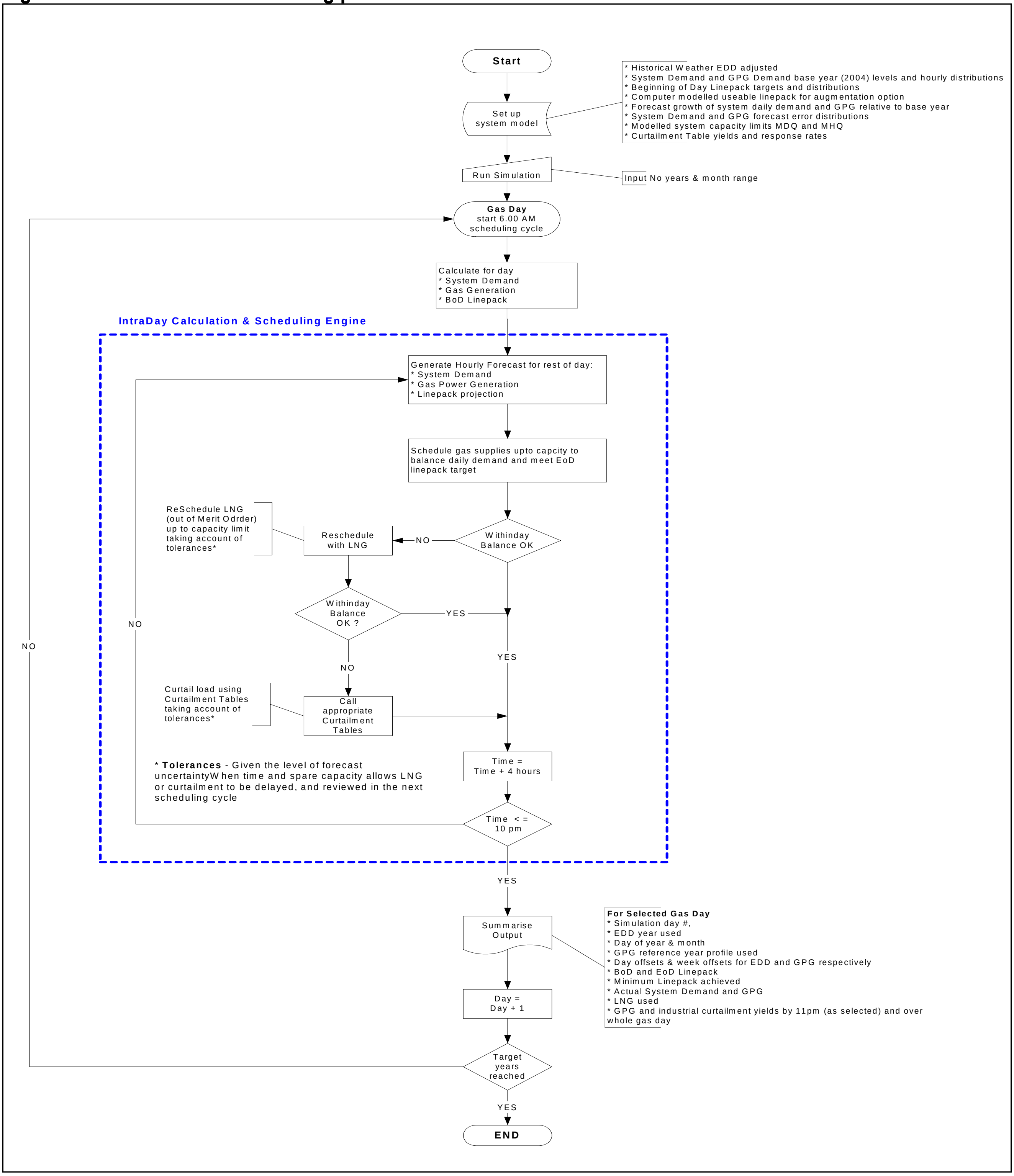
Appendix 2 Mass balance model

The mass-balance gas model has been developed by Concept Consulting for VENCorp and simulates gas days for conditions that vary according to the model settings defined by the user. It processes data into a form useable by the model either as constants or dynamically, with generic calculations representing daily scheduling and any associated decision making regarding LNG and curtailment.

Figure A1 illustrates the modelling process. The user defines data inputs. Once the simulation has commenced, the data for the simulated day is calculated and passed to the module that schedules the system over the gas day. Simulating the scheduling of the system over the gas day essentially involves doing the following: from a start-of-day linepack level and given forecast and actual supply and demand, schedule supply and LNG injections and, if necessary, curtailment so as to meet an end-of-day linepack target, and do this in a manner broadly consistent with how the system might be managed. The daily scheduling module performs all calculations instantaneously and is a self-contained module in that it does not refer to any external input data that change across simulations. Results for the simulated day are stored, and the process repeated for the next simulated day until the simulation is complete. Results for all the simulated days are then written to a separate sheet of the workbook.

Simulated days are independent insofar as the effects of decisions made in one day do not carry over to the next.

Figure A1 - Mass balance modelling process



Appendix 3 Glossary

AER	Australian Energy Regulator.
BassGas	A supply proposal to bring gas undersea from the Yolla field in Bass Strait for processing at Lang Lang and injection into the PTS near Pakenham.
Compressor	A compressor is a gas pumping device that increases the capacity of a pipeline by increasing gas pressure in the pipeline to assist the flow of gas.
Competition Benefits	The increase in economic welfare arising from competition within markets.
CRA	Charles River Associates.
Culcairn	Location of the interconnection of the PTS and the NSW (APT) gas transmission systems. The location of the injection and withdrawal points between these two systems.
Curtailment	The curtailment or interruption of a Customer's supply of energy at its delivery point which occurs when a system operator intervenes or an emergency direction is issued.
Customer	Any party who purchases energy and consumes energy at a particular premises. Customers can deal through Retailers or may choose to become Market Participants in their own right.
Dandenong City Gate	Location at which gas leaves the transmission system and enters the Distribution system at Dandenong
EDD	Effective Degree Day. A measure of coldness that includes temperature, sunshine hours, chill and seasonality. The higher the number, the colder it appears to be and the more energy will be used for area heating purposes. EDD is used in forecasting and estimating basic meter energy consumption.
GAPR	Gas Annual Planning Review.
Gas Code	National Third Party Access Code for Natural Gas Pipeline Systems.
GPG	Gas Power Generation.
GJ	Gigajoule, SI unit (10^9 joules).
kPa	Kilopascal. 1000 pascal, where pascal is gauge pressure (strictly kPag) in excess of atmospheric pressure as defined in AS1000-1979 "The International System of Units (SI) and its Application".
Linepack	The quantity of pressurised gas stored or contained in a gas pipeline.
LNG	Liquefied natural gas.
LNG Storage	The facility located at Dandenong for the storage of LNG.
MDQ	Maximum Daily Quantity.
MSOR	Market and System Operating Rules.
NEM	National Electricity Market

NIEIR	National Institute of Economic and Industry Research.
NPV	Net Present Value.
PIWG	Pipeline Investment Working Group.
PJ	Petajoule, SI unit (10^{15} joules).
PTS	Principal Transmission System (gas) - Victoria's primary high pressure gas transmission system. It transports gas from Longford in the south-east of Victoria, Iona in the south west of the State along the SWP, and the inter-connection with the NSW system at Culcairn, north of Albury, to the Melbourne and regional demand centres.
Regulatory Test	Regulatory Test for Major Network Augmentations – Promulgated by the AER in accordance with Clause 5.6.5A of the National Electricity Rules.
SEA Gas	South East Australia Gas Pipeline- a major new pipeline development delivering gas from the Minerva offshore gas field in the Otway Basin to South Australia and connected to the PTS.
SWP	South West Pipeline – major gas transmission pipeline for transportation of gas between Iona and the underground storage and Lara, adjacent to Geelong.
System injection point	A connection point on the transmission system which is designed to permit gas to flow through a single pipe into the transmission system, which may also be, in the case of a transfer point, a system withdrawal point.
System security	The operation of the transmission system in a safe and reliable manner and in accordance with the system security guidelines.
TJ	Terajoule, SI unit (10^{12} joules).
TNSP	(Electricity) Transmission Network Service Provider.
Uplift	A charge imposed on Market Participants based on a daily allocation, made in accordance with the MSO Rules, of the total ancillary payments payable in respect of that day, if any.
VCR	Value of Customer Reliability.
VUE	Value of Unserved Energy
VicHub	The connection between the Duke Energy owned Eastern Gas Pipeline and the GasNet owned pipeline at Longford to allow injections into and withdrawals from the Victorian gas market.