4 AVAILABLE AND PROSPECTIVE SUPPLIES AND STORAGE

This chapter presents information provided by gas producers, *Storage Providers* and *Market Participants* with regard to total available and prospective gas supplies for the next 5 years.

Available supply is that which will be made available to the market through commercial arrangements between *Market Participants* and *Producers* or *Storage Providers.*

Prospective supply is not yet contracted but is potentially available to the Market and is assumed to be limited by the minimum of the capacities of the producer, the *Storage Provider*, or the gas transmission system.

The reported supply does not necessarily represent all gas supplies that will be made available to the Market. Additional *Participants* may enter the Market or additional supplies may be contracted from the Cooper, Otway, Bass or Gippsland Basins and made available at existing or new injection points.

4.1 Review of Gas Supply in 2001

Gross supply, the sum of all injections at all injection points, was 212 PJ for the 12 months to October 2001, however this includes gas supplied for refill of the TXU Underground Gas Storage (UGS) over summer and exports. The net supply for use by gas customers including gas power generation was 202 PJ.

Table 4.1 shows the net[21] supply that occurred at each injection point for the 12 months to October 2001 and for May to September 2001.

Longford remains the primary supply source providing almost 99% of net gas supplies used by gas customers supplied through the gas market. This share actually increased in 2001 as the WTS load has been supplied through a connection at North Paaratte since 28 November 2000 due to depletion of the Paaratte field.

The Iona supply figure includes UGS supply, a small amount of toll processing at the UGS facility, and some supply in late 2000 from the depleted Paaratte field. Iona net supply is small due to replenishment of UGS over the summer months.

The Culcairn annual net supply has been reduced by exports of almost 1 PJ in early 2001.

The May to September data reflects the UGS winter peak shaving role, accounting for almost 6% of supply in this period. UGS provides a considerably a greater proportion of supply on colder days.

Table 4.1 Gas Supply 2001

Period	Longford	Culcairn	Iona	LNG
12 months to 31 October	98.8%	1.6%	-0.4%	0.0%
May to September	92.0%	2.2%	5.8%	0.1%

[21] Net injections $=\Sigma$injections- Σwithdrawals over the period.

4.2 Longford Supplies

Table 4.2 summarises contracted and prospective peak day gas supplies reported for the Longford injection point. Contracted supply MDQ is 841 TJ/d for 2002 and declines progressively to 810 TJ in 2005 and 2006. However, Exxon-Mobil/BHP have advised that *"additional supplies on a firm and non-firm basis may be made available to the Victorian system up to pipeline constraint, subject to the review of available capacity, expansion alternatives and future interstate sales commitments, together with the agreement of commercial terms"*.

Prospective supplies may be available on firm or non-firm basis up to the pipeline capacity of 990 TJ/d.

Table 4.2 Longford Supplies (TJ/d)

Year	Contracted	Prospective	Total
2002	841	149	990
2003	841	149	990
2004	834	156	990
2005	810	180	990
2006	810	180	990

Though 841 TJ is contracted, a smaller quantity is expected to be bid into the market on a daily basis as occurred in 2001.

Additional supplies to those in Table 4.2 may also be contracted, for example, expiry of the Gascor *Gas Release* contract[22] by 2004 means that replacement supplies of at least 30 TJ/d might be sought at or near Longford.

4.3 TXU Underground Gas Storage (UGS) and Toll Processing

Reported supply from UGS and toll processing for winter 2002 to 2006 is aggregated as Iona Supplies in Table 4.3.

UGS supply capacity has been revised from 200 TJ/d to 250 TJ/d following testing in April 2001. The reported contracted quantity is somewhat lower, however it is understood that supply utilising the full UGS supply capacity will be made available to the market on a daily basis through a non-exclusive commercial arrangement with a *Market Participant*. It is understood that this additional capacity is available to other *Market Participants*.

The supply available at Iona for 2002 is 265 TJ/d which includes toll processing of gas from other Otway gas fields. The current toll processing capacity is in excess of 70TJ/d and is only limited by the capacity of gathering lines from Otway gas fields.

VENCorp has set the injection capacity at Iona to 275TJ/d for supply to both the SWP and to the WTS.

TXU has revised the UGS holding capacity from 10 PJ to 10.7PJ following replenishment over summer 2000/2001. Some 8.6 PJ has been contracted by *Market Participants* for winter 2002 to 2005 dropping to 6.6 PJ in 2006. Inventory prior to winter 2002 will depend on withdrawals into the UGS prior to each winter. The UGS is generally expected to be fully replenished before each winter except under

[22] Some 15 PJ of the Gascor contract at up to 50 TJ/d was made available to new market entrants for a limited period.

extraordinary circumstances associated with either a supply emergency or unseasonally very cold autumn weather accompanied by very large demand from gas power generation.

Table 4.3 Iona supplies (TJ/d)

Year	Contracted	Prospective	Total
2002	182	83	265
2003	172	93	265
2004	172	93	265
2005	172	93	265
2006	133	132	265

Storage capacities reported by *Participants* are shown in Table 4.4, however, as for the UGS supply capacity, the full inventory of up to 10.7 PJ will be available to the gas market through a non-exclusive commercial arrangement between the Operator and a *Market Participant*.

Table 4.4 Iona UGS Storage Capacity (PJ)

Year	Contracted	Prospective	Total
2002	8.6	2.1	10.7
2003	8.6	2.1	10.7
2004	8.6	2.1	10.7
2005	8.6	2.1	10.7
2006	6.6	4.1	10.7

4.4 Supplies from the Culcairn Interconnect

Total capacity for net imports of gas to Victoria using the Springhurst compressor is 50 TJ/d, however, up to 92 TJ/d is possible given suitable conditions on the NSW APT transmission system and availability of the GasNet compressors at Bulla Park and Young in NSW.

Contracted and prospective Culcairn supplies are summarised in Table 4.5.

Table 4.5 Culcairn Supplies (TJ/d)

Year	Contracted	Prospective	Total
2002	13.7	36.3	50.0
2003	13.7	36.3	50.0
2004	0.0	50.0	50.0
2005	0.0	50.0	50.0

2006	0.0	50.0	50.0

Supply of about 14 TJ/d has been contracted for 2002 and 2003 on a firm basis. Additional supplies will be available on a non-firm basis. Based on expected NSW loads and the usual operation of the APT system, it is expected that at least 28 TJ/d will be available during colder winter months and this figure has been assumed for supply-demand analysis in Chapter 6. During non-winter months supply bids to about 50 TJ/d are expected as occurred in 2001.

4.5 Liquefied Natural Gas Storage (LNG)

The LNG facility at Dandenong is suitable for needle peak shaving but is occasionally required to maintain system security on surprise cold days or to provide additional supply when gas fired power generation is scheduled on very high demand days. LNG is a critical supply in the management of system security should there be a sustained supply or transmission failure from Longford or Iona.

The LNG tank has a nominal storage capacity of 12,000 tonnes (655 TJ)[23] of which 8400 tonnes (459 TJ) is currently allocated to *Market Participants*, 3000 tonnes (164 TJ) is held in reserve by VENCorp for system security, and the balance of 600 tonnes contracted to a third party.

The current LNG contracts with *Market Participants* will end in December 2002 and a review by March 2002 will determine the future of the VENCorp security reserve allocation. Regardless of the outcome of the review it is expected and assumed in this planning review that the LNG inventory and capacity available to the gas market will not materially change. It is clear that LNG remains a critical component of supply and is required for system security.

It is assumed that LNG inventory will be full or nearly full prior to each winter. Exceptions would be when the tank is partly depleted due to an unplanned incident or emergency or due to unseasonally extreme autumn demand accompanied by gas power generation as occurred in May 2000.

For planning purposes it is assumed that up to 150 TJ/d will be available for needle peak shaving[24]. At this rate, *Market Participant* LNG inventory could be depleted in 3 days, however, it is expected that LNG Market price bids will generally reflect the scarcity, flexibility and security value of this supply.

LNG liquefaction is arranged on a planned monthly basis to replenish stock levels. Accelerated rates of liquefaction are possible depending on the time of the year and the degree of depletion.

4.6 Other Prospective Supplies

The following projects are likely to impact the gas market within the planning period or longer term.

4.6.1 Bass Basin

Supplies from the Yolla and the adjacent White Ibis fields may be developed by 2004 making available 20 PJ/y to the market. This equates to at least 54 TJ/d. The project, which involves construction of an undersea pipeline to bring gas onshore and to Melbourne, is now more likely given that the Duke Longford to Bell Bay (Tasmania) pipeline project is going ahead.

The Kipper gas field will be brought on in the medium term to supplement depleting fields supplying the market from Longford.

[23] 1 tonne of LNG has an energy equivalent of 0.0546 TJ.

[24] This is based on 16 hours vaporisation at the maximum capacity of 180 tonnes/h.

4.6.2 Gippsland Basin

Some 60 PJ of gas over 5 years has been contracted from the Patricia Baleen field by a *Market Participant*. At 12 PJ/y this equates to at least 33 TJ/d. The gas may become available by around 2004. Supply could involve a connection with the EGP, a direct connection to the Longford pipeline, or commercial swap arrangements.

4.6.3 Otway Basin

The Minerva gas field will come into production when the Port Campbell to South Australia pipeline project is completed. Large offshore gas fields such as Geographe and Thylacine would then be more likely to be developed in the medium to long term. Such developments are very likely to involve a connection to the GTS at or near Iona.

4.6.4 Other Supply and Pipeline Developments

Tables of additional supply and pipeline developments that may impact the Victorian market are provided in Appendix O and Appendix P, respectively.

5 SYSTEM CAPACITY

This chapter commences by explaining how capacity is determined. Infrastructure projects are then summarised before a detailed assessment of system capacity is presented.

New sections in this APR include: The capacity of the WTS; augmentation of the Longford pipeline, the effect of injection profile on capacity; and spare summer capacity for gas power generation.

5.1 Determination of System Capacity

System capacity is the maximum demand that can be met on a sustained basis over several days given a defined set of operating conditions. System capacity is a function of many factors and accordingly a set of conditions and assumptions must be understood in any assessment of system capacity. These factors include:

- load distribution across the system;
- hourly load profiles throughout the day at each delivery point;
- heating values and specific gravity of injected gas at each injection point;
- initial line pack and final line pack and its distribution throughout the system;
- ground and ambient air temperatures;
- minimum and maximum operating pressure limits at critical points throughout the system; and
- power and efficiency of compressor stations.

System capacity is determined using a calibrated computer model of the gas transmission system. VENCorp uses the Gregg Engineering WinFlow (steady state) and WinTran (transient) software modules. A sample set of conditions for the determination of system capacity is provided in Appendix K.

The VENCorp gas transmission system model has been calibrated using actual winter 1999, 2000 and 2001 metered gas injections and withdrawals on selected high and moderate demand days. Refinements from the calibration process ensure that the model continues to accurately simulate the observed pressures and flows throughout the system.

Demand distributions used in capacity modelling are normally based on forecasts of general load and exclude demand for gas fired power generation and exports. Gas power generation scenarios are modelled as required.

5.2 System Infrastructure Developments

5.2.1 Capital Works Completed in 2001

The following works were completed in 2001:

- ***Iona Compressors:***GasNet installed two 300 kW reciprocating compressors at Iona. One compressor can provide adequate pressures into the 150 mm pipeline from Iona to North Paaratte to provide supply to the WTS primarily during the non-winter period. The compressors are currently undergoing testing and the testing/debugging period is expected to extend into May 2002;
- ***Colac connection:***Colac was connected to the SWP in December 2000 and the consumers' existing TLPG appliances and reticulation were converted to natural gas by May 2001;

- ***Walla Walla connection:*** Walla Walla has been connected to the Interconnect (between Barnawartha and Culcairn in NSW);
- ***Tatura upgrade:*** Tatura meter was upgraded to cater for an increase in load;
- ***Valley Power (Loy Yang B):*** Edison Mission has constructed a 13.5 km 300 mm pipeline from the Longford pipeline near Traralgon to the Loy Yang B power station. This pipeline is capable of delivering up to 100 TJ/d;
- ***Somerton lateral:*** GasNet has constructed a 3.4 km 250 mm pipeline lateral from Epping to Somerton. This pipeline is expected to have a capacity of 2 TJ/h to supply the 150 MW AGL Somerton gas generator; and
- ***Iona Processing Plant Upgrade:*** TXU completed work early in 2001 at Iona so that UGS can operate at pressures up to 10,000 kPa[25] and fully utilise the capacity of the SWP. During April 2001 the plant was tested at an average flow rate of 240 TJ/d over a twelve hour period. The plant was able to supply a peak flow rate of over 300 TJ/d. The UGS injection capacity has since been revised to 250 TJ/d. The new compression facilities also allow withdrawals into UGS of up to 90 TJ/d.

5.2.2 Committed Capital Works

- ***Duplication of the 350mm Brooklyn to Corio Pipeline:*** The duplication from Brooklyn to Paradise Rd (11 km short of Lara) with 500 mm pipe will significantly increase the capacity between Melbourne and Iona in both winter and summer modes, if and when it proceeds.

  VENCorp modelling scenarios with high flows of up to 330 TJ from Iona to Melbourne indicate that the proposed heater capacity and/or the number of regulator runs at Brooklyn city gate would need to be increased.

  Although this augmentation is built into current TUOS *Tariff* arrangements, the duplication will only proceed when the capacity is required. The demand forecasts indicate that this will not necessarily be required in the planning period.

  Participants interested in additional capacity should be aware that a full duplication from Brooklyn to Lara would allow the new loop to operate at higher pressures (to 10,000 kPa) with significantly greater capacity than of the current proposal.

5.2.3 Potential Capital Works

- ***New Connections:*** A new connection for supplying a large gas power station in the Geelong region by late 2002 has been proposed. Connections required to supply other gas turbines are quite likely within the planning period. New connections for large cogeneration proposals in the Gippsland and Melbourne withdrawal zones, possibly requiring some pipeline duplication may also proceed.
- ***New Withdrawal Points:*** Mickleham Grande, Yarra Glen, Churchill, Officer, and Simpson.
- ***Upgrades:*** It is proposed that the Toolamba Road limiter and the Hopkins Road limiter be upgraded or bypassed in 2003. This work will impact the relevant gas *Distributor* if the limiter is bypassed. Pressures downstream of the limiter will be higher possibly requiring the *Distributor* to install heaters at some city gates (regulators).

[25] The SWP is licensed to operate at 10,200 kPa if gas is supplied at Iona at 38°C or lower, however, the gas can be injected at up to 50°C and the pipeline is licensed to 10,000 kPa under these conditions. Accordingly, VENCorp modelling assumes a limit of 10,000 kPa.

- ***NSW Compressors:*** GasNet has compressors located at Bulla Park and Young, NSW, which may be modified or removed at some stage though there are no plans to do so at present;
- ***Gooding Compressors:*** GasNet is reviewing the need for restaging Gooding compressors to more closely align the operating point to future needs given the significant changes in the sources of supply over the last 3 years;
- ***Guildford to Carisbrook Duplication:*** This duplication might be required if a very large new load connects downstream from Carisbrook or, in the longer term, after system loads have increased sufficiently; and
- ***Springhurst Compressor Reversing:*** This would enable greater supply to Northern Victoria or for exports to NSW and is covered in section 5.3.3; and
- ***Supply to Swan Hill/Kerang Region:*** The Loddon Murray Gas Supply Group (LMGSG) has been given approval from the ACCC to seek tenders for supply of gas to the region. This could be achieved from Mildura, Echuca or Bendigo. Bendigo is considered to be the most likely option if this project succeeds. Reference to section 5.6.1 shows that the capacity available at Bendigo is greater than at Shepparton and it is expected that the additional capacity available at Mildura is less than at Bendigo.

5.3 Pipeline Capacity

5.3.1 Longford System Capacity

The Longford to Dandenong pipeline system capacity is 990 TJ/day for defined assumptions and operating conditions.

5.3.2 NSW Interconnect Imports

The NSW Culcairn Interconnect currently has a capacity of 50 TJ/d utilising the Springhurst compressor. This capacity increases to 92 TJ/d subject to the continued availability of the GasNet compressor at Young NSW and favourable operating conditions in the connecting APT system. Up to 35 TJ/d can be imported without use of either compressor.

5.3.3 NSW Interconnect Exports

Winter

The capacity to export to NSW via Culcairn is limited by the length (260 km) and the small diameter (300 mm) of the pipeline from Wollert to Barnawartha. The Springhurst compressor is not configured for exports. The capacity to export depends on system demand as shown in Figure 5.1. Export capacity is 30 TJ/d when system demand is 800 TJ/d but falls to under 11 TJ/d when GTS demand exceeds 1100 TJ on 1 in 20 peak days.

The modelling assumes that the APT system in NSW can receive and transport the delivered gas beyond Culcairn, however current exports to the APT system are constrained to about 17 TJ/d which is the peak load between Culcairn and Young, NSW.

The modelled export capacity is directly subject to uncertainty in local forecast loads particularly at Albury/Wodonga. For example, an increase of 1 TJ in demand at Albury-Wodonga reduces export capacity by 1 TJ/d.

Reconfiguring and/or relocating Springhurst compressor for northbound flows or part duplication of the pipeline could increase export capacity. Modelling has been carried out to assess the suitability of the Springhurst compressor for exports. Additional export capacity of about 6 TJ/d can be achieved as shown in Figure 5.1, however, the existing compressor power is too large, and the location is also suboptimal. Additional export capacity of about 10 TJ/d would be achieved by use of an equivalent compressor located at Euroa.

Summer

The capacity to export in summer is affected by the same factors as for export during winter. In summer the export capacity is restricted by the APT system's capacity to accept gas. This is dependent on the APT being able to run the Bathurst/Orange/Lithgow (BOL) compressor to compress gas from the Young-Culcairn lateral into the main pipeline to Wilton or into the Bathurst/Orange/Lithgow lateral.

Modelling indicates that the export capacity in summer is up to 37 TJ assuming that two compressors at Wollert and the BOL compressor are operating. Exports up to 30 TJ were achieved in February 2001.

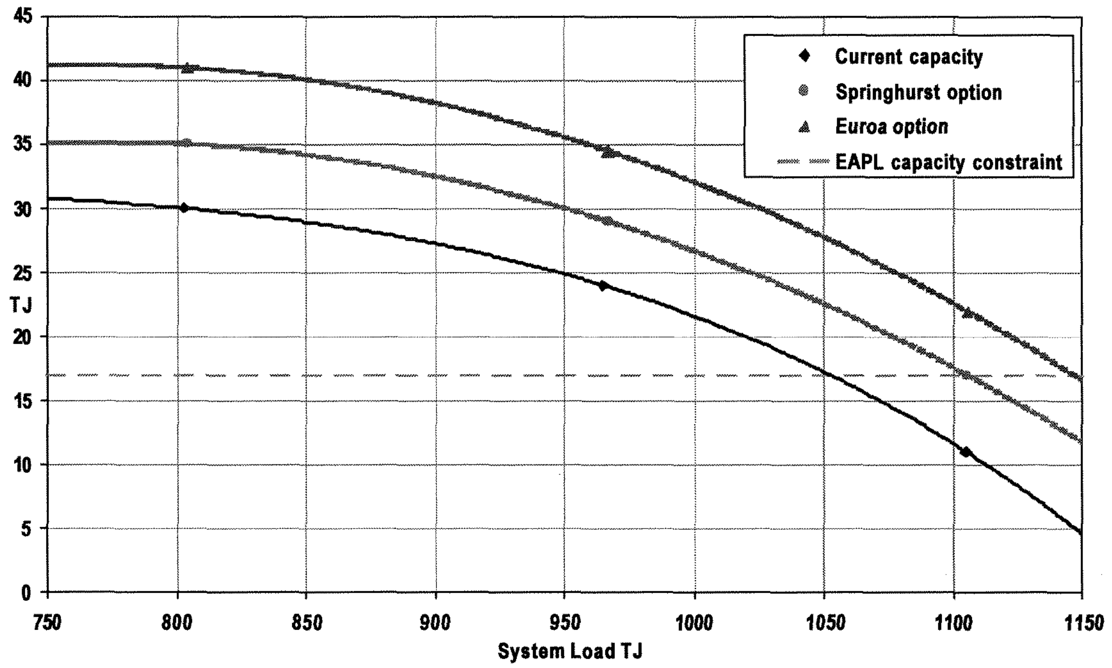

Figure 5.1. Culcairn Interconnect Export Capacity

5.3.4 South West Pipeline Capacity from Iona

The South West Pipeline (SWP) has a capacity of about 260 TJ/d in winter.

The relationship between SWP capacity and Iona maximum delivery pressure is illustrated in Figure 5.2. In practice the SWP must be kept above 3800 kPa to enable operation of the Iona plant. Every 25 TJ/d increment in injection capacity requires the supply pressure to increase 1000 kPa resulting in an increase in linepack in the SWP of about 14 TJ. If the scheduled injections at Iona vary greatly from one day to the next, VENCorp must be aware of this so that appropriate pressures are targetted the previous day to ensure that the nominated quantity can be transported.

In addition to the UGS facility, an on site toll processing plant at Iona can process gas from other Otway sources and provide additional supply. The toll processing capacity is currently over 70 TJ/d and is currently limited by the capacity of the gathering lines from Paaratte, Heytesbury and other Otway fields.

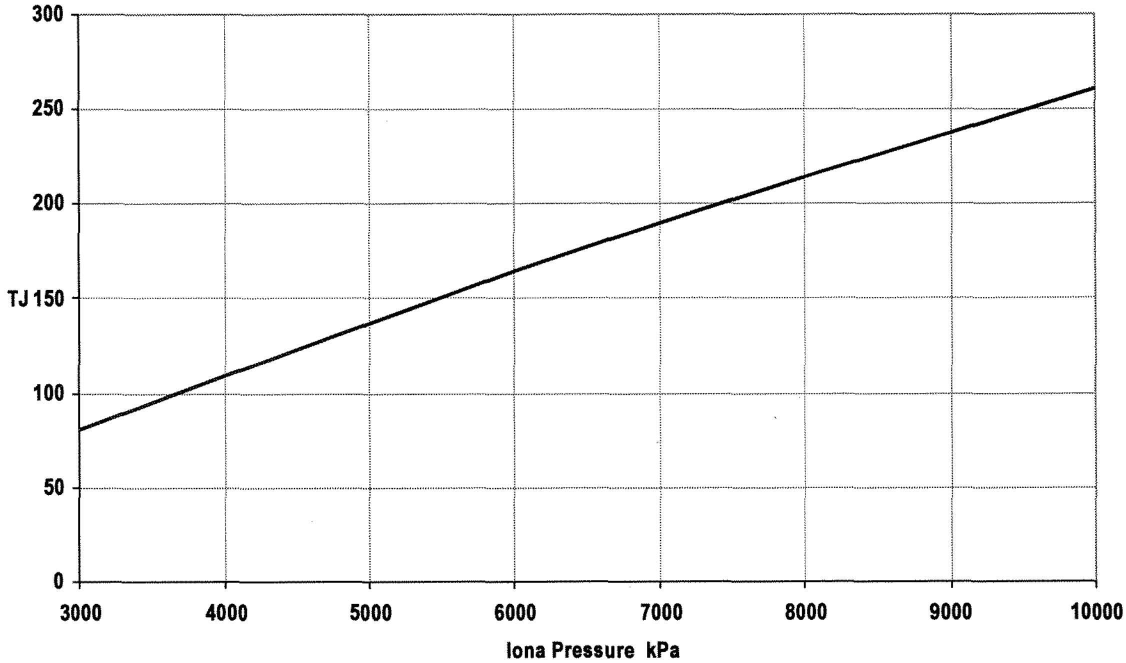

Figure 5.2 Capacity of SWP from Iona

5.3.5 South West Pipeline Capacity to Iona

The SWP has a capacity to deliver up to 90 TJ/d to Iona in summer at the required minimum delivery pressure of 3800 kPa for both withdrawal into the UGS and to supply the WTS.

The capacity depends on system demand as shown in Figure 5.3. The upper solid line is based on general demand whereas the dashed line models additional high industrial load and/or demand for gas power generation by AES Yarra at Newport. The capacity to Iona is reduced by about 3 TJ/d due to an assumed load increase of 60 TJ/d [26] in the Newport load.

The capacity is also very dependent on demand in the Geelong zone downstream from Brooklyn compressor station. A significant reduction in Geelong demand due to a major industrial closure in June 2001 will directly translate to an increase in capacity to Iona.

[26] A worst case scenario of additional demand of 60 TJ over general load over the 12 hours from 9am is assumed. Corresponding injections are assumed to be uniform over 24 hours.

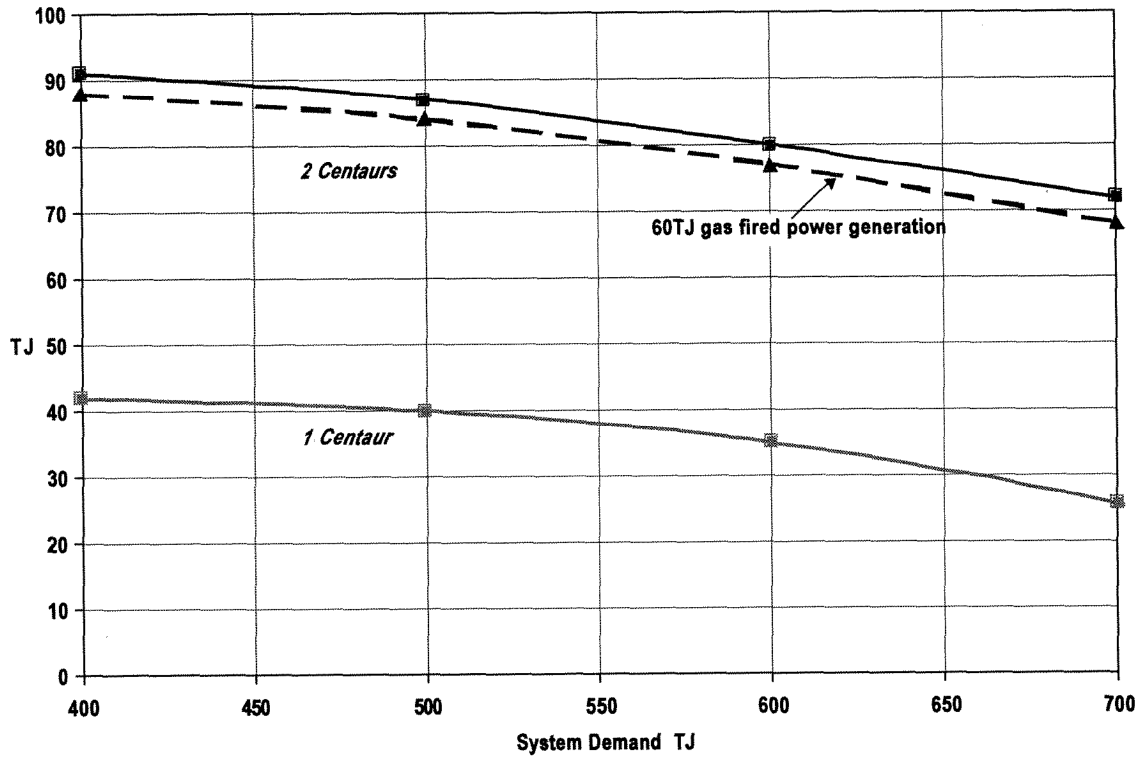

Figure 5.3 South West Pipeline Capacity Iona

The capacity is reduced considerably if either of the two 2800kW (Centaur) compressors at Brooklyn compressor station fails. There is no redundancy at Brooklyn if two Centaurs are operating. Failure of one Centaur when system demand is 600 TJ/d would reduce capacity from 80 TJ/d to 35 TJ/d as shown in Figure 5.3.

The Brooklyn to Paradise Road Corio loop 500 mm pipeline duplication proposal would increase this capacity by 21 TJ/d for a system demand of 600 TJ/d. A full duplication from Brooklyn all the way to Lara would increase the capacity to Iona by 39 TJ/d under the same conditions.

5.4 Gas Transmission System Capacity

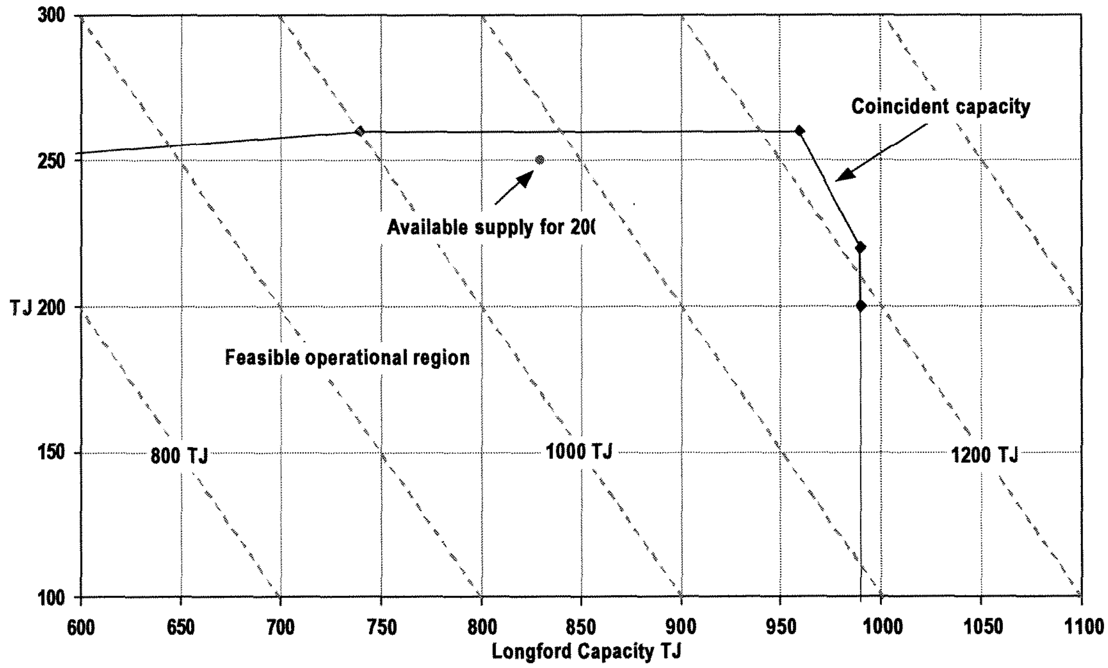

Figure 5.4 Gas Transmission System Capacity

The modelled maximum individual capacities of the Longford pipeline, the NSW Culcairn Interconnect, and the SWP are 990 TJ/d, 50 TJ/d[27] and 260 TJ/d respectively. Due to overall transmission system constraints these individual capacities are not fully additive. The capacity of the GTS based on 1 in 20 peak day forecasts has been modelled to be about 1210 TJ/d assuming supplies from Longford and Iona alone.

Figure 5.4 depicts GTS system capacity under a simplified scenario where net flow at the Interconnect is assumed to be 0TJ/d. The top boundary of the feasible operational region is determined by maximising supply from Iona while system demand is progressively increased, with the balance of supply coming from Longford. Similarly, the right hand side boundary maximises supply from Longford with the balance of supply from Iona.

Total system demand from 800 TJ/d to 1300 TJ/d is represented by the parallel, oblique dotted lines. Each point along a system demand line in the enclosed region represents a different feasible combination of supply from Longford and Iona.

The system capacity increases to 1270 TJ/d when gas imports from NSW are included and to 1390 TJ/d with LNG. Allocating additional capacity of 20 TJ for the WTS means that the total theoretical system capacity is about 1410 TJ/d.

5.5 Western Transmission System

It is planned that the WTS will be integrated with the GTS by late 2002 although this has been postponed on more than one occasion. In the meantime the WTS is supplied through a connection to the GTS at North Paaratte.

[27] The Interconnect import capacity is 92 TJ with Young compressor NSW, however this compressor is not included in the Service Envelope Agreement.

In winter, it is generally expected that gas will be injected at Iona from underground storage and in summer gas will be withdrawn at Iona to refill the underground storage.

5.5.1 Capacity to Supply the WTS in Winter

In winter, gas can be injected into the SWP at up to the MAOP of 10,000 kPa enabling injection into the WTS at its MAOP of 7400 kPa, thus maximising capacity of the WTS. Figure 5.5 shows the capacity of the WTS versus the supply pressure at Iona.

Assuming supply from Iona is available at up to the pipeline maximum operating pressure (7400 kPa), the capacity of the WTS based on the peak day load distributions is 28 TJ/d, well in excess of peak demand. However, with more moderate levels of Iona injection of between 50 TJ/d and 100 TJ/d capacity to the WTS will be limited to about 18 TJ/d.

If Iona does not inject on a winter day the WTS would have to be supplied by Longford from Brooklyn. Modelling has been carried out for a day when system demand is 800 TJ, which is approaching the contracted level of supply at Longford. Under these conditions the WTS can be supplied from Longford by running compressors at Brooklyn and Iona.

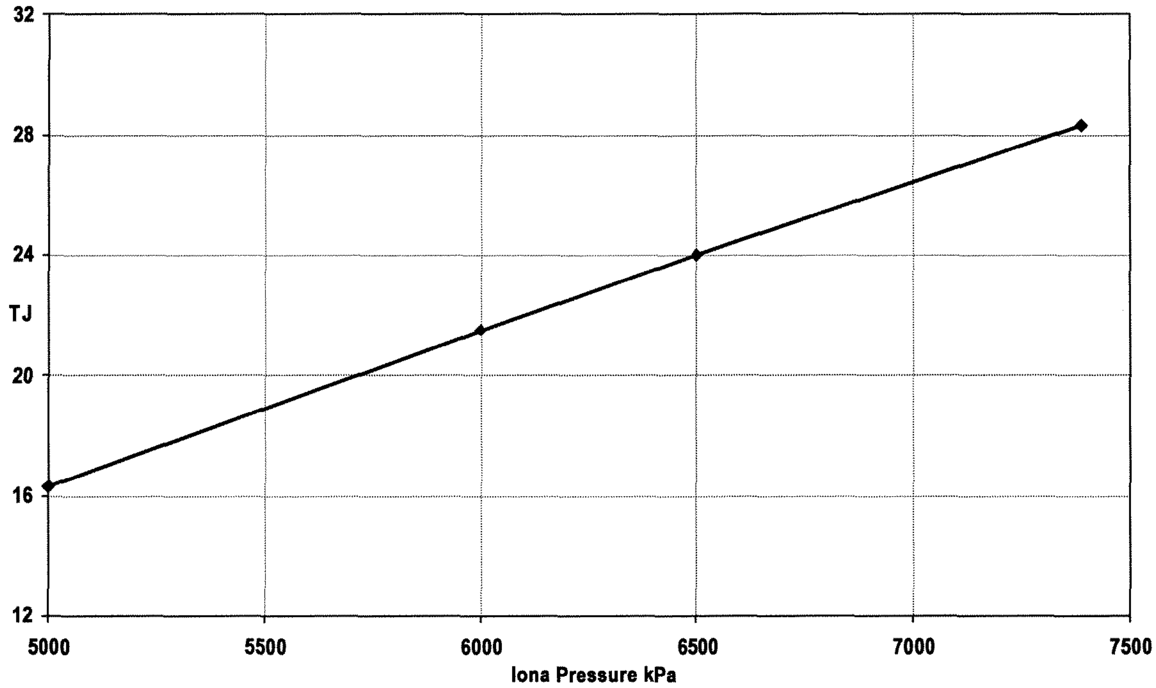

Figure 5.5 WTS Capacity

5.5.2 Capacity to Supply the WTS in Summer

In summer, when gas is transported to Iona for UGS refill, the minimum pressure obligation at Iona is 3800 kPa. Under these conditions it is assumed that the Iona compressor can operate at up to 7400 kPa discharge pressure with a nominal output power of 298 kW. This gives the maximum summer capacity of about 16 TJ/d allowing for reductions in power due to high ambient temperature and internal losses. This capacity will be reviewed after summer when operational data becomes available.

The Iona compressors ensure Longford gas can be delivered to the WTS during summer when gas is being withdrawn for underground storage.

5.6 Local Capacity Limits

5.6.1 Capacity on Laterals

Local pipeline capacity limits have been modelled for a number of lateral pipelines in the system by determining the magnitude of additional load (with the current peak load profile) that can be supplied on each lateral. This has been done for two scenarios at each location. The first is an export scenario that assumes exports of 17 TJ to NSW while the second is an import scenario and assumes 50 TJ of imports from NSW. In both scenarios the initial system demand is the winter 1 in 2 peak day 2002.

The results are summarised in Table 5.1. Additional load on the Shepparton lateral, the Murray Valley lateral, and at Albury/Wodonga is very limited unless physical supply is available via the NSW Interconnect.

The Albury/Wodonga case relates closely to the analysis of export constraints discussed in 5.3.3. There is a one for one trade-off in meeting either increased exports or new load at Albury/Wodonga. As deduced from Figure 5.1, exports are constrained to about 18 TJ at a 1 in 2 peak demand of 1,051 TJ. As exports at Culcairn are 17 TJ in this scenario, additional load at Albury/Wodonga that could be supplied from the south would be limited to about 1 TJ. Under the import scenario, the Albury/Wodonga loads are only limited by the extent of these imports and the capacity of the city gate and distribution system downstream.

Under the export scenario, the capacities available on the Murray Valley and Shepparton laterals are 2 TJ and 4 TJ respectively.

Under the import scenario, the excess capacities are 27 TJ, 14 TJ respectively indicating considerable growth potential beyond the current peak loads. In this case the limits are set by the local capacity of the lateral pipelines rather than the Wollert-Culcairn pipeline.

An additional load of 10 TJ could be added at either Ballarat or Bendigo before minimum pressure obligations are breached under the export scenario.

If all the available spare capacity is used by an additional new load at one of the locations, say Wodonga, this would reduce the spare capacity at all the other locations in that zone to zero. In this case Murray Valley, Shepparton and Bendigo would have zero spare capacity if an additional load of 1 TJ is applied at Wodonga.

Table 5.1 Local Capacity Limits

Lateral	NSW Import		NSW Export	
	Spare Capacity TJ	Pressure Constraint	Spare Capacity TJ	Pressure Constraint
Wodonga/Albury	50	n.a.	1	Culcairn
Murray Valley	27	Koonoomoo	2	Culcairn
Shepparton	14	Shepparton	4	Culcairn
Bendigo	19	Carisbrook	10	Carisbrook
Ballarat	20	Ballarat	10	Carisbrook
Lurgi	14	Morwell Back-up	14	Morwell Back-up
Geelong	17	Corio	10	Corio

For more information on the interdependency of spare capacity in the northern and western zones, please refer to the "AMDQ Transfer Algorithm" published on the VENCorp website.

In summary, the results show that supply from the Interconnect is the obvious alternative to the system augmentation required in order to provide capacity for peak day supply to northern Victoria.

Similar analysis was undertaken for additional load at Cranbourne on the Morwell to Dandenong lateral, otherwise known as the Lurgi pipeline. This is a more complicated system due to potential supply via the 'Morwell back-up regulator' at Dandenong. Under the scenario where the back-up regulator remains closed an additional peak load of about 14 TJ on the Lurgi lateral could be served.

5.6.2 Capacity for Gas Power Generation

Modelling has been carried out to determine the capacity of the gas transmission system to deliver gas for peak electricity generation at various locations on the system. The modelling scenarios assumed that gas power generation will occur under summer conditions but to be conservative a gas load for late summer has been modelled.

Under summer conditions it is expected that supply of gas will be from Longford with gas likely being transported to Iona for underground storage and gas could be injected or withdrawn at Culcairn.

The locations considered for analysis have been chosen to represent a region rather than a specific site. The profile of load used was a 12 hour profile, on for the first 12 hours of the gas day (from 9am) and off for the rest. This is a severe profile for transport purposes.

The results of the analysis showing the daily and hourly quantities available in each region are shown in Table 5.2 below for supply to one site only and for the same site with AES Yarra Newport operating at 100% load for 24 hours.

Table 5.2 Capacity for Summer Gas Power Generation (TJ)

Location	Sole Load		With Newport	
	MDQ	MHQ	MDQ	MHQ
Traralgon	192	16.0		
Gembrook	208	17.3	158	13.1
Wodonga	26	2.1	26	2.1
Shepparton	15	1.2		
Bendigo	29	2.4	29	2.4
Ballarat	14	1.1	13	1.0
Lara[28]	36	3.0	34	2.8
Newport	200	16.6		

If multiple sites take gas at the same time, the pipeline capacity limits on the different sections of the system will affect the total power generation load available. The power generation capacity available if

[28] There is a 1 for 1 trade off between load at Lara and withdrawals at underground storage. The figure shown is for zero UGS withdrawal.

Newport operates at full rate all day are shown in the right hand columns. Sites north of Wollert are unaffected by Newport because these sites are limited by pipeline capacity, but Gembrook is directly affected, almost one for one. Newport affects Ballarat and Lara to a much lesser degree.

The power generation capacity available around Traralgon is less than is available downstream. This is not intuitively expected and is due to a limit on the suction pressure at Gooding compressor station. The power generation capacity available at Bendigo, Shepparton and Wodonga are with no imports or exports through Culcairn. If Culcairn exports gas the values in the table will be lower and conversely, if gas is imported the values will be greater. In the case of Wodonga any gas imported through Culcairn could be available at Wodonga, limited only by the capacity of the *Interconnect*. Pipeline limits reduce the power generation capacity to other locations.

The Ballarat area is supplied predominantly from Brooklyn and therefore the pipeline diameter, and MAOP limit power generation capacity.

The load in the Lara area, which includes Geelong, directly affects the transport capacity to Iona and the western system. The figure in the table above does not include any gas delivery for underground storage, but includes supply to western towns.

The power generation capacity available at Newport is the same as would be available at Dandenong, however, the load at Newport reduces the capacity at Iona. The 200 TJ at Newport reduces the transport capacity to Iona by 20 TJ, due to the reduction in pressure at Brooklyn compressor station.

It can be seen that the largest quantities of gas can be made available on the 750 mm pipeline from Longford to Brooklyn and from Pakenham to Wollert.

It should be noted these figures are indicative and it must be remembered that loads in one zone will directly affect other loads in that zone. The modelling has been carried out on the basis that the peaking generation load was known to be coming online. If this type of load starts up suddenly, the system will not be able transport the load indicated in the table to the northern part of the system. At Wodonga in particular, at least 24 hours notice would be required to build up a sufficient level of linepack.

5.7 Dependence of Capacity on System Linepack

5.7.1 Linepack

Linepack, the pressurised volume of gas stored in the pipeline system, is essential to enable gas transportation through the pipeline network throughout each day. Injections into the system are normally at an approximately constant hourly rate whereas demand varies throughout the day, particularly in winter due to temperature sensitive load. Linepack is mined during the first half of the gas day (from 9am to 9pm) which includes the morning and evening peaks when demand is greater than supply. During the second half of the day (overnight), linepack is replenished because supply is greater than demand. Typical load profiles are shown in Appendix M.

5.7.2 Pipeline Capacity and Linepack

Modelling has been carried out to determine the dependence of system capacity on beginning of day (BOD) linepack under scenarios using supply from Longford only and where end of day linepack is the same as beginning of day linepack ie there is no linepack 'mining'.

This analysis underlines the importance of achieving end of day linepack targets during periods of high demand in order to enable the pipeline to operate at maximum capacity on the following day.

Figure 5.6 shows that if BOD linepack is lower than the optimum level (used to achieve maximum capacity), capacity is reduced.

In the scenarios analysed the optimum BOD linepack was about 630 TJ[29] and the corresponding maximum capacity (or maximum demand that can be met) was about 1,000 TJ.

In Figure 5.6 capacity is expressed as a percentage of the maximum pipeline capacity that can be achieved whereas the BOD linepack level is expressed as a % below the optimum linepack level.

Reduced capacity due to a sub-optimal BOD linepack can be partly offset by injecting more gas at Longford as shown by the Longford injection curve.

LNG is available to manage events where linepack might fall below critical levels causing a threat to system security. The LNG enables greater transportation from Longford so that a demand equal in magnitude to the maximum pipeline capacity can be met without building or mining of linepack, as shown by the LNG Injection curve. An interesting finding is that the amount of LNG used for this purpose is, to a very good approximation, equal to the level of BOD linepack under the optimum level required for full capacity.

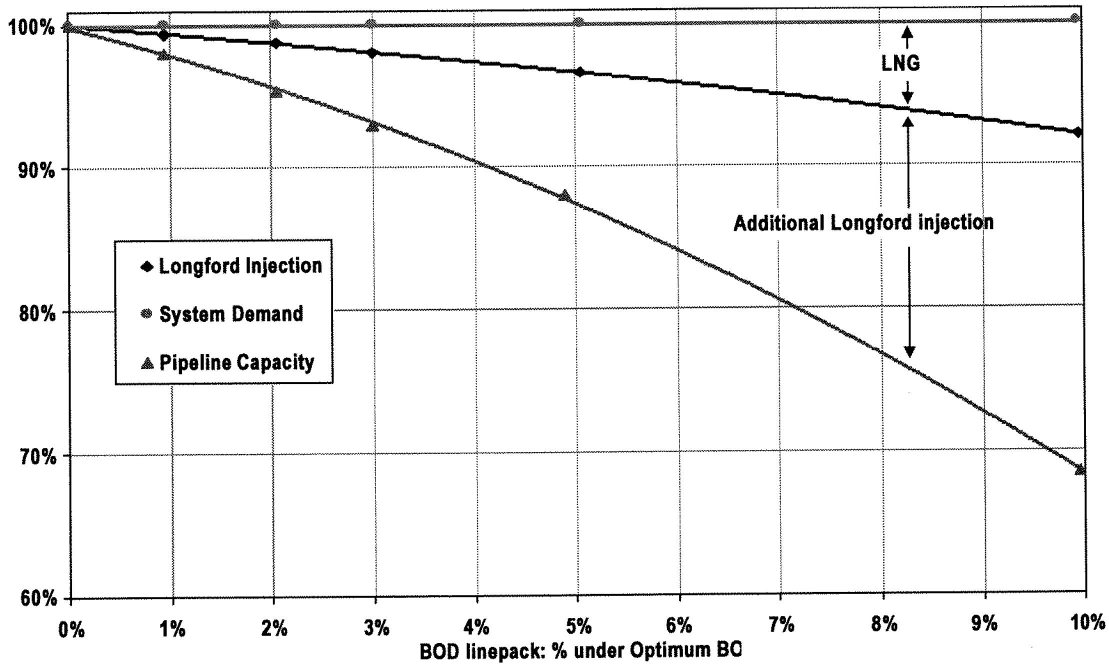

Figure 5.6 Pipeline Capacity (% of Maximum) vs BOD Linepack

5.8 Dependence of Pipeline Capacity on Load Location

Detailed analysis has been carried out on changes in capacity of the Longford pipeline caused by moving load from one location on the system to another. Generally, moving load upstream towards the injection point results in an increase in pipeline capacity.

In the modelling analysis, a load of a standard *Tariff D* profile (large industrial/commercial sector) was subtracted from Dandenong City Gate (DCG) and a load of the same profile was added and then maximised at the test point with a commensurate increase in Longford supply. The ratio of the

[29] These figures include active and passive linepack.

maximised load at the test site to the load removed from the DCG 'hub' is termed the Locational Factor (LF).

LFs ranging from about 2.75 to 3.35 were found for *Tariff D* loads at existing offtakes on the Longford pipeline upstream from Pakenham to Sale. The profile used in these cases was total Gippsland Tariff D load excluding Paperlinx, Maryvale (which would be treated separately). The LFs at these locations are very sensitive to the hourly profile of the load. Loads with *Tariff V* profiles (residential and small commercial/industrial sector) have lower LF ratios. The Lurgi lateral has an LF of 2.7.

All locations downstream from the outer ring main junction near Pakenham had an LF of about 1.0. The downstream LFs are relatively insensitive to load profile due to buffering by the large amount of upstream linepack.

A simple example of how LFs apply would be to consider a closure of a 10 TJ *Tariff D* site in Melbourne - effectively at DCG. This would enable an additional load of about 27.5 TJ of the same profile to be met at Traralgon (LF=2.75). Of course, additional supplies from Longford would have to be arranged.

A summary of the results on a schematic showing the GTS is provided in Appendix J.

On lateral pipelines the amount of load that could be relocated was limited (or capped) due to local pipeline constraints.

5.9 Dependence of Pipeline Capacity on Delivery Pressure and Injection Profile

Pipeline capacity is dependent on injection pressure and profile as well as demand profile and distribution. The effect of injection pressure and profile are discussed.

5.9.1 Delivery Pressure

Modelling has been carried out to determine the degree that the maximum delivery pressure at the injection point affects the capacity of the system. The higher the pressure available the greater the pipeline capacity. The relationship for the Longford pipeline is shown in Figure 5.7, which shows the pipeline capacity as a percentage of capacity where the maximum delivery pressure is 6,700 kPa versus maximum delivery pressure.

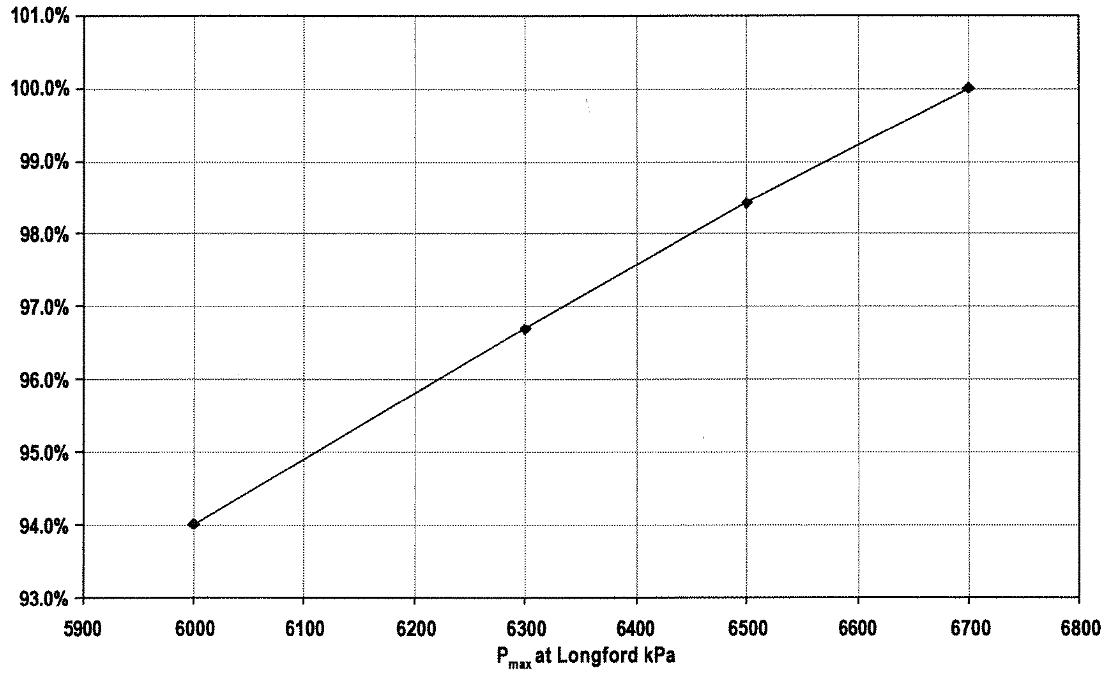

Figure 5.7 Pipeline Capacity versus Maximum Delivery Pressure

5.9.2 Delivery Profile

The usual injection flow rate at Longford is constant over a day with variation due to rescheduling. Under these conditions the pressure varies throughout the day.

Modelling shows that if a constant delivery pressure can be maintained the pipeline capacity is increased by almost 5%. This profile maximises pipeline capacity but the flow varies as shown in Figure 5.8.

Dual level profiles with higher injection rates during the daytime and compensating lower rates overnight have been modelled to approximate the constant pressure case. These are defined by the % increase in injection rate above the flat injection rate during the period from 9am until 1am.

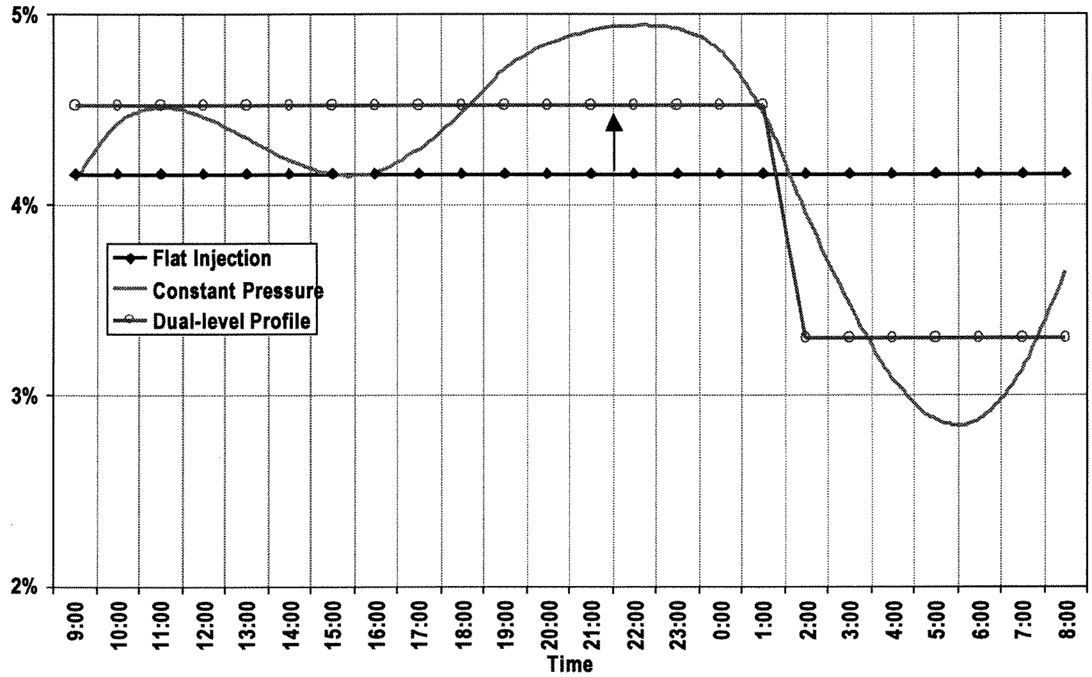

Figure 5.8 Flow Profiles

The modelled capacity relative to the flat injection profile is shown in Figure 5.9. An increase of about 4% in capacity can be achieved using this approach.

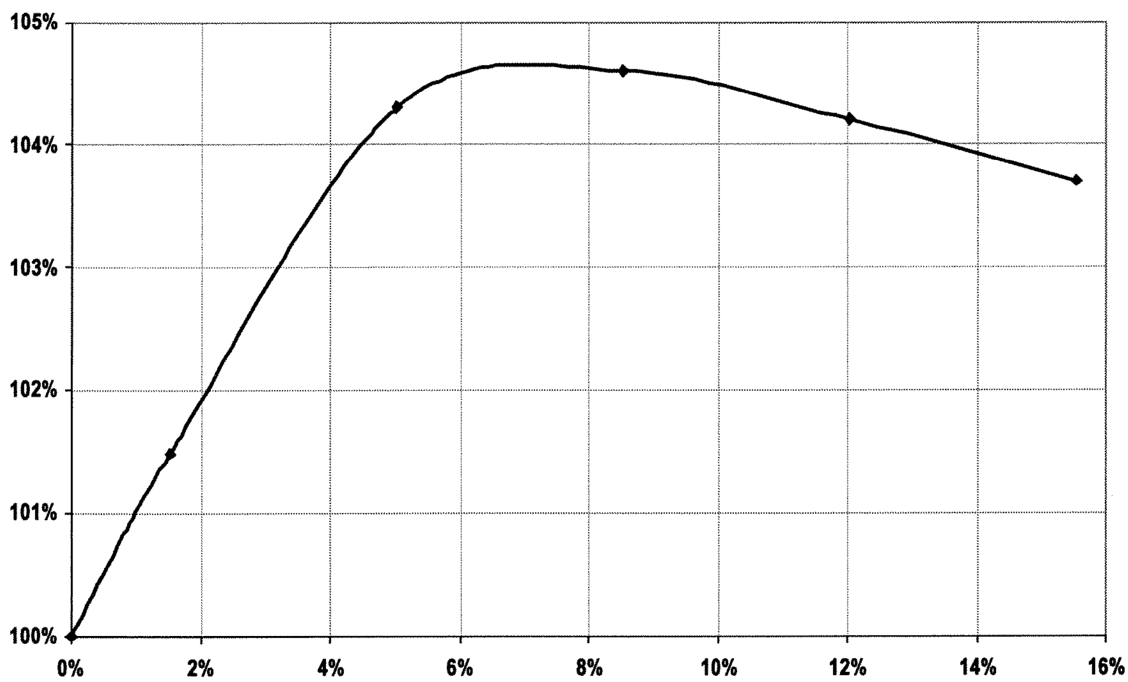

Figure 5.9 Capacity versus Injection Profile

However, whether the gas plant is capable of achieving this would need investigation and commercial arrangements would need to be put in place.

5.10 Potential Gas Transmission System Augmentations

5.10.1 Corio Pipeline Duplication

The Brooklyn to Paradise Road loop mentioned in Section 5.2.2 provides an increase in SWP capacity to Iona in summer by 21 TJ/d and by 70 TJ/d from Iona in winter.

The proposed loop is 11 km short of Lara. A complete 500 mm duplication from Brooklyn to Lara is more sensible and would result in a considerably greater increase in SWP capacity.

5.10.2 Brooklyn Compressor Upgrades

In summer when the Brooklyn compressors are compressing gas to Iona, there is a rotor-dynamic constraint in one compressor, which limits the power available. However, even with available maximum power the discharge pressure achievable is lower than the MAOP of the Corio pipeline thus not fully utilising this pipeline capacity. Capacity could be increased with engines with greater power but the compressors might require restaging. Current capacity is sufficient to enable underground storage to be refilled without being upgraded.

Restaging of compressors might be required in the medium to long term to meet Ballarat and Sunbury peak winter loads.

5.10.3 Longford-Melbourne Pipeline Duplication

The capacity of the Longford to Melbourne pipeline is 990 TJ/d based on the current winter peak load distribution and a standard set of operating conditions. This capacity is fully allocated as Longford AMDQ and there is currently no spare capacity available. Constructing any of the remaining loops between Line Valve 4 and Bunyip would increase the Longford pipeline capacity. Table 5.3 below shows the potential duplications commencing at the Melbourne end and progressing upstream.

Table 5.3 Longford-Melbourne Pipeline Augmentations

	Loop	Location	Length (km)	Diameter (mm)
1	Drouin to Bunyip	LV 7 - LV 8	13.6	750
2	Yarragon to Drouin	LV 6 - LV 7	19.1	750
3	Gooding to Yarragon	Gooding CS - LV 6	15.1	750
4	LV 4 to Gooding	LV 4 - Gooding CS	14.3	750

The modelled capacity increases have been determined for loads with a winter system peak profile and a flat profile applied downstream of Dandenong.

The cumulative capacity increase of the Longford to Dandenong pipeline versus the total length of duplication is shown in Figure 5.10. The capacity increase is roughly linear however the first loop appears to be less effective than average due to pipeline dynamic effects. Modelling shows that this first loop actually provides the greatest capacity increase per unit length of any of the possible loops when constructed first, so there are obviously benefits gained from additional linepack from subsequent looping. The incremental capacity from each loop is dependent on the sequence. The transmission pipeline owner will determine the looping order if and when required.

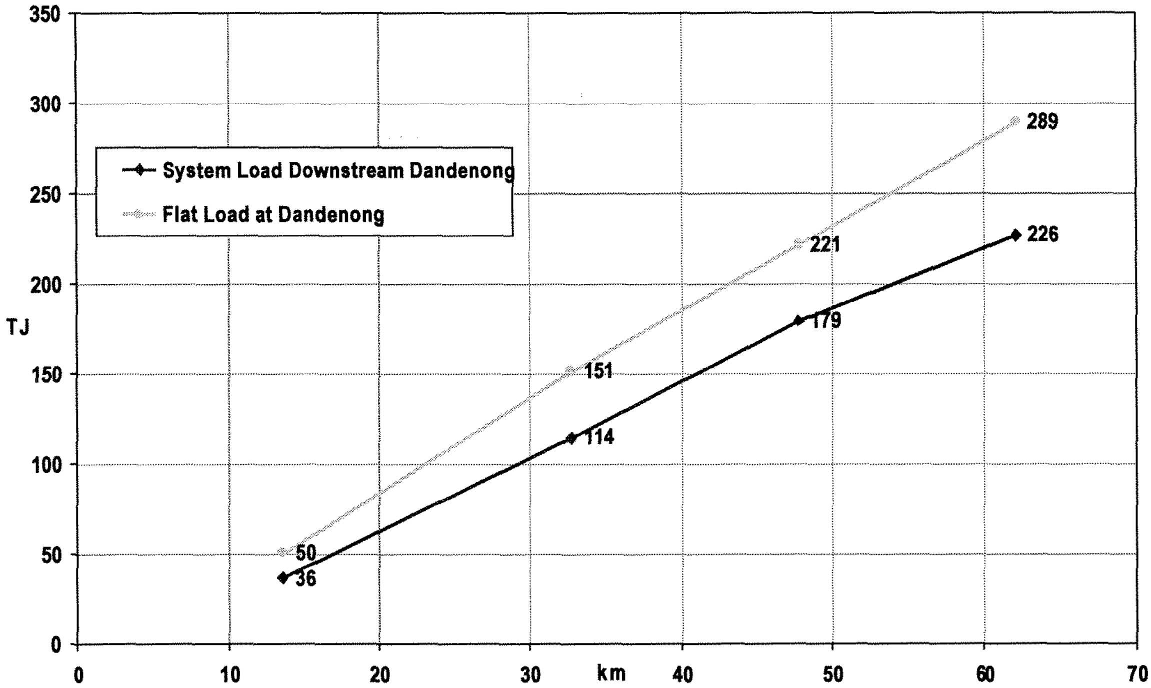

Figure 5.10 Longford-Dandenong Pipeline Capacity Increase versus Total Length of Looping

5.10.4 Brooklyn to Wollert Pipeline

In the longer term, under extremely high flow rates from Iona, a pipeline from Brooklyn to Wollert would facilitate transportation of Iona gas around the state. This pipeline could be given consideration if very large quantities of gas from new Otway fields are injected for the Victorian market or for export to NSW. The Corio pipeline duplication would be required before this pipeline.

5.11 Distribution System Infrastructure

A Distribution Business has reported the possibility of a link from the Pakenham-Wollert pipeline (outer ringmain) to the metropolitan ringmain probably at Lilydale. This will have the effect of shifting load off Dandenong and increasing Dandenong pressure slightly but reducing Wollert pressure slightly. Although total capacity to Melbourne would increase marginally it is expected that there would be a small reduction in capacity to northern zone. The capacity in the eastern side of the metropolitan area will increase. This work is tentatively proposed for 2004 and as no details are currently available the effects cannot be quantified. Modelling confirms that pressures in the metropolitan ringmain fall to levels that require reinforcement such as that proposed above.

On days of very high demand it is sometimes necessary to open the valve at Templestowe[30] to allow additional flows of up to 20 TJ/d from Wollert City Gate into the UE (Multinet) network to meet high demand and maintain supply pressures. The valve operation is performed by agreement of the distributors and is controlled by the distributors. This is sound practice and assists overall transmission system capacity by elevating the minimum pressure at Dandenong City Gate.

Under conditions of high injection rates at Iona, high pressures will be experienced at Corio and Lara. Pressures in the range between 6000 kPa and 7000 kPa can be expected but under some conditions

[30] This valve is normally closed. It is located on the 450 mm inner ring main at the boundary between Stratus and Multinet DB networks.

could be as high as 7400 kPa and this will require heaters at city gates to ensure temperatures supplied to the distribution system are not too low.

Heaters at Lara are adequately sized to ensure that gas injected into the Corio pipeline from the SWP is not lower than 2°C.

5.12 Reduced Capacity due to Plant Outages

System capacity is dependent on the availability of system infrastructure and can be reduced by planned or unplanned outages. The impact on capacity of such outages is discussed below.

5.12.1 Springhurst Compressor

The import capacity of the Interconnect will be reduced from 50 TJ/d to 35 TJ/d if the Springhurst 4,500 kW compressor is not available.

5.12.2 Brooklyn Compressors

An outage of either of the 2800 kW Centaur compressors (Unit 10 or 11) at Brooklyn will constrain summer transportation to Iona to 30 to 40 TJ/d as shown in Figure 5.3. Both compressors are required to provide summer capacity to Iona in excess of 50 TJ/d though the second compressor is currently classed as a redundant unit.

During winter, redundant 850 kW Saturn compressors and the Centaur compressors minimise the risk of reduced capacity.

5.12.3 Major Compressor Stations

Gooding, Wollert and Brooklyn compressor stations, unless otherwise specified above, have redundant compressor units available to minimise the risk of transportation constraints due to compressor failure.

5.12.4 LNG Facility

The LNG vaporising plant includes three pressure pumps and three vaporisers. A failure or a planned outage of any one of these can reduce the capacity of 150 TJ/d by 30% to 45% depending on the unit.

5.12.5 SCADA/Communication Systems

Failure of any of these systems will require manual operation and reduce control effectiveness with consequent effects on operational schedules.

5.12.6 Cyclical Plant Maintenance

The capacity impact of scheduled plant maintenance and outages for 2002 is presented in the monthly planning review section.

The maintenance schedule is fairly constant from year to year and the annual schedule for 2002 can be applied reasonably well across the 5 year planning period.

5.13 Long Term Capacity Constraints

Modelling has shown that the outlet pressure of the Hopkins Road limiter will need to be increased over time to maintain adequate minimum pressures to the inlet to Sunbury. A pressure of 3400 kPa is expected to be required by 2004 or 2005. In the longer term pressures at Sunbury will drop to unacceptable levels and some reinforcement will be required. This will depend on whether load on the Sunbury lateral continues to increase at the rate forecast.

Additional modelling was carried out to simulate years out to 2010. Pressures at Bendigo and Carisbrook will fall below their required minimums in about 2008. Either lower minimum inlet pressures must be accepted or reinforcements will be required to the transmission system. The analysis was based on the assumption that load distributions remain the same as the forecast for 2006. System augmentation could be required earlier if new loads materially change the load distribution from the forecast.

5.14 Limitations of Capacity Modelling

Modelled capacities are subject to uncertainty because they depend on forecast inputs, assumed operating parameters, operating conditions and a mathematical representation of the system. Uncertainties are estimated at about 1% for high capacity runs such as Longford capacity but can be up to 10% for small capacities such as the export capacity of the Interconnect or the capacity of a lateral pipeline.

Assuming the modelled maximum capacities are correct, they can only be achieved with correct demand forecasting and operational scheduling on the day and if conditions are similar to those assumed in the model runs. It is often the case that extremely high demand days that test system capacity are also surprise cold days, scheduling is not optimum and the maximum capacities cannot be realised. The beginning of day operating conditions are critical on peak days and the level of linepack, in particular, is a critical factor. Refer to Section 5.7.2 for more information.