Remaining economic life of GasNet's transmission assets

A report prepared for
GasNet Australia (Operations) Pty Ltd

by
Saturn Corporate Resources
in association with GHD Ltd and
Sharpe Legal Partners

18 February 2002

Contents

Page no.

Contents (cont.)

Page no.

Contents (cont.)

Page no.

6. Continued

Executive summary

Introduction

1. In setting tariffs for use of gas transmission networks the allowable depreciation rate is a critical element. The more rapidly an asset depreciates the greater the initial revenue, *ceteris paribus,* required to deliver a target or regulated rate of return from it and conversely the less rapidly an asset depreciates the lower the revenue, *ceteris paribus,* required to result in a given rate of return.

2. In setting depreciation rates the starting point is generally the technical (design or expected physical) life of an asset. For a new asset this is defined in terms of the expected technical life when the asset is installed or commissioned. But for an existing asset the remaining technical life is the appropriate measure of technical life.

3. The technical (design or expected physical life) of an asset is often, however, not a satisfactory indicator of how long an asset is expected to contribute a satisfactory revenue stream as it may become commercially marginal or sub-marginal before its technical life is reached. Generally economic factors are the main reason why an asset becomes commercially unviable before its technical life is reached. Even if an asset is well maintained and quite capable of producing goods or services for which it was designed, when it can no longer contribute to financial targets of the owning operating entity its economic life is effectively over.

4. Institutional factors such as competition and environmental factors can also have an effect on remaining life of assets through impacts on demands and on the resources (here gas reserves) on which they depend. It is important to consider these possibilities particularly for such long lived assets as pipelines.

5. A regulatory regime which recognises the important economic role of technically long lived assets and the uncertainties they face over their **potentially** long life will, *ceteris paribus*, attract more investment in these assets. For a major factor of production such as natural gas the attraction of investment in new transmission assets and in maintenance of existing transmission assets is vital for enhancing efficiency of energy and overall economic systems through provision of system security and increased competition.

Technical life of GasNet's transmission assets

6. The technical life (TL) is defined as represents the assessment of the total useful life that can be expected when the assets are initially installed based on the quality of materials used, environmental conditions under which the asset operates and in the case of transmission pipes the temperature and pressure at which the gas is being carried through the network of pipes.

   GHD has reviewed current industry standards and has concluded that the assessment and experience of GasNet Australia (Operations) Pty Ltd (hereinafter referred to as GasNet) and its predecessors with regards to its particular pipes remains valid. As stated in a GHD 1997 report for Transmission Pipelines of Australia Pty Ltd "there are few benchmarks for pipelines operating under identical conditions and maintenance regimes" (section 5.2) and therefore concluded that management assessment of 60 years based on historical experience, although conservative, was valid.

Based on this specific experience of the 'insitu' pipes under review the GHD 1997 report adopted a technical life of 60 years for the pipeline assets.

Thus on review GHD has concluded that no technological or major physical events have occurred that substantially impact on the TL assessment derived in the 1997 valuations. It is therefore recommended that the TL of 60 years be retained.

7. By the application of the technical life to the GasNet transmission network the remaining technical life (RTL) of each asset was calculated using the formula: design life less life expired to date = remaining life where life expired to date = report date less date installed and commissioned.

8. The network has been categorised into Elements to aid analysis. These Elements primarily focus on the gas reserve and the pipeline that transports the gas from the reserve. (Refer to **Economic factors** below.)

- Element A = Longford/Dandenong pipeline;
- Element B = South West pipeline system which can be divided into two sub-elements:
    - Element B (S/U) – the South West element including the Underground Storage System;
    - Element B (R) – the rest of Element B; and
- Element C = the rest of the system.

The TL of 60 years has been applied to the GasNet pipe assets to determine the weighted average remaining life by asset grouping by the nominated element A, element B and element C.

Element A	28 years
Element B (total)	57 years
Element C	37 years
Element B (S/U)	59 years
Element B (R)	52 years

Economic factors

9. The gas reserves which a pipeline carries to markets are of crucial importance to the pipeline's remaining economic life. Remaining life of reserves has two main determinants:

(i) quantity of reserves; and

(ii) demands on those reserves.

Estimates of economically recoverable reserves are based on proved, probable and likely commercial reserves. In addition estimates are made of undiscovered, based on probability of reserves being proven given the geological characteristics of the region. As undiscovered reserve estimates are very uncertain, recoverable reserve estimates generally only include proved, probable and other likely reserves which have not yet been declared commercially viable. These estimates are prepared for each geological basin and for fields within those basins.[1]

1 Notes on reserve definitions and estimates are contained in **Appendix B.**

10. Different reserves affect different transmission assets. For example the main transmission link between Longford and Melbourne depends on Gippsland Basin reserves and the South West system depends mainly on Gippsland, Otway and Bass Basin reserves, and the rest of the system the above basins and other basins connected to the Victorian system. Accordingly in this report analysis is conducted on three system elements.

    A. The Longford to Melbourne transmission element.

    B. The South West transmission element (divided into two sub-elements).

    C. The rest of the system.

11. When Victorian reserves are depleted there may be some use of pipelines for reverse haulage of gas from other basins such as Cooper/Eromanga (northern South Australia, Northern Territory and south-west Queensland, but which has limited reserves to service South Australian, New South Wales and Queensland markets) but more importantly Western Australian/Northern Territory and Papua-New Guinea basins.

    On the other hand, new high capacity pipelines from remote reserves could result in some pipeline portions being bypassed.

12. Eastern Australia basins only comprise about 20 per cent of Australian reserves, whereas unconnected Western Australian and Northern Territory basins comprise about 80 per cent of total Australian reserves. If these reserves were connected to eastern Australia this would ensure ample supplies in the region until about 2060 given potential reserve and demand increases (very difficult to predict post-2020). However, the gas would likely be higher priced than current eastern Australian gas to cover the higher transmission costs, although viable tariffs for larger capacity/long distance pipelines can be competitive with smaller capacity/shorter distance pipelines.

13. It should be noted that the official reserve figures are not universally accepted and many analysts believe the official recoverable reserve (ORR) figures are below ultimately recoverable reserves. For example they point to recent company announcements that Otway Basin reserves from recently discovered fields may be in the 3,000-4,000 PJ range (official recoverable reserves 526 PJ) and in the 2,000-3,000 PJ range for the Bass Basin (official recoverable are 376 PJ). Both these basins have been lightly explored compared with the Gippsland Basin. And new reserve additions continue to be made to the Gippsland and Cooper/Eromanga basins. Thus, actual reserves (AR) in south east Australian basins **may** be well above the official reserve estimates.

14. Nevertheless, it is important to base the current analysis predominantly on official recoverable reserves as possible recoverable reserve additions may not eventuate; possible recoverable reserve additions should, however, be noted and their implications analysed.

15. The withdrawals picture from the eastern Australian basins is changing rapidly with new pipelines being built to meet growing demands for gas, particularly for electricity generation, in a competitive environment.

    As demands grow in a competitive environment new pipelines may be built. As a result some parts of the current system may be bypassed, that is some parts may become stranded assets. This possibility is examined in the factor analysis for each system element. Note that the competitive situation facing each system segment will depend on tariffs and gas supply costs in the markets served.

Projections: forecasts, drivers, discussion

16. Natural gas demand projections by State and sector are prepared periodically (every 1-3 years) by the Australian Bureau of Agricultural and Resource Economics (ABARE) and the National Institute of Economic and Industry Research (NIEIR).

    Forecasts depend on economic growth, economic structural change and relative prices of end-use energy in competing sectors. For example, electricity versus gas in space and water heating and gas versus coal in electricity production.

    NIEIR's latest national demand projections were prepared for the Australian Gas Association (AGA) in 1999. New (October 2001) ABARE projections show that the 2001 demand forecasts are below those prepared in 1999 and about 17 per cent below NIEIR's 1999 projections, for the 2000-01 to 2014-15 period.

    Thus there are significant variations between ABARE and NIEIR forecasts which are mainly due to differing views on the use of gas for electricity generation, particularly in Queensland. There is considerable debate and divergence of opinion on the respective roles of gas and coal and, to a lesser extent, the role of renewables in electricity generation over the next 20 years. Since the 2001 ABARE report was completed Queensland has announced a program to boost gas use in electricity production by 2005.

Implications for reserves and pipelines

17. The NIEIR forecast projects about 14,000 PJ of demand over 1999-00 to 2014-15 against official reserves (including AGA's CSM supply estimate) of about 15,000 PJ. In 2014-15 NIEIR's projected demand in eastern Australia is about 1,160 PJ suggesting depletion of eastern Australian basis by 2015-16. This compares with the AGA (Webb, 2001) estimate of projected demand of 13,226 PJ, and official recoverable reserves of about 15,000 PJ (including recoverable coal seam methane – CSM – by 2015) over 1999-00 to 2014-15. Allowing for use over 2015-17 of about 2,000 PJ the AGA estimates put depletion of eastern Australian official recoverable reserves in about 2016-17.

    On the basis of ABARE's 2001 demand projections for the period in eastern Australia (about 10 per cent below their 1999 projections on which AGA analysis was based), depletion of Eastern Basin **official recoverable reserves** would occur in about 2019-20.

    Based on ORR and the various demand projections suggests a depletion period for eastern Australian basins of 2016-2020.

18. Decreases in reserves are unlikely: lower real gas prices compared with alternatives would slow reserves development, as would future work which showed official recoverable reserve estimates were too optimistic. Both these conditions are considered very unlikely.

    It is more likely that actual reserves will prove to be higher than official recoverable reserves as a result of increased exploration for gas, better exploration techniques which would likely result in improved exploration success, and higher real gas prices which would result in a greater exploration effort and the viability of higher cost reserves.

For **our** actual reserve (AR) estimates in eastern Australian basins of 25,000 PJ the depletion period would be 2025-2030.

19. Increases in demands above those projected could come from higher economic growth rates, lower relative (to other energy sources) gas prices, technological change favouring natural gas usage and policy changes (see below). Higher economic growth rates than those assumed by forecasters are considered unlikely, but lower gas prices relative to coal and petroleum products, could result from more stringent greenhouse policies (see below).

20. Decreases in demand below those projected could come from lower economic growth rates, higher relative gas prices and technological change favouring energy sources other than natural gas.

    Higher relative gas prices could come from greater competition from renewable energy sources (particularly in electricity generation, for example wind, biomass) and from reliance on higher cost (at point of use) gas reserves, for example WA/NT and CSM reserves.

    Technological change favouring competitors to gas could come from electro-technologies and from renewable sources.

21. When Western Australia/Northern Territory gas and CSM is introduced into eastern Australian markets, relative gas prices are likely to rise and dampen gas demand growth but to a level which is unlikely to significantly impact on the remaining economic life of GPU GasNet's transmission assets.

    These demand change possibilities analysed are considered to have been adequately taken into account in the NIEIR and ABARE projections.

    Higher relative gas prices and the other demand drivers assessed above are much more likely to affect the remaining economic life of distribution assets than transmission assets as they could significantly affect distribution assets in particular locations serving particular markets. For transmission assets gas volumes carried may decrease but are unlikely to decrease to uneconomic levels.

Institutional factors

22. Competition policy in the gas area is mainly concentrating on upstream structure, pipeline access and full retail contestability.

    Upstream structure is of particular concern in eastern Australia as onshore fields are dominated by Santos and its partners, while offshore Esso-BHPP dominate. This lack of upstream competition is tending to favour higher ex-plant prices leading to lower demands for natural gas, particularly in the electricity generation market where lower gas unit capital costs often do not offset higher fuel costs.

    Overall we judge that competition is increasing leading to some movement towards lower ex-plant prices and, *ceteris paribus*, higher gas demands. In the longer term as eastern Australian reserves are depleted, gas prices will depend on transmission tariffs and costs of, and competition in, WA/NT reserves development.

    The pipeline access regime is also encouraging upstream competition.

Fuel retail contestability, although its effects are constrained by upstream concentration and low distribution and retail margins, is also tending to lower prices and increase demands.

23. In the wake of the United States pull out from the Kyoto Protocol to reduce greenhouse gas emission growth over the 1990-2012 period, greenhouse policy trends are difficult to predict.

We judge that even if Australia does not ratify the Kyoto Protocol and thus not formalise the commitment to reduce greenhouse gas emissions, Australia will continue to work towards the target of holding average 2008-12 emissions to 108 per cent of 1990 emissions.

Natural gas is the most greenhouse benign of fossil fuels having about 40 per cent lower emissions per unit of energy contained than coal (variation from brown to black) and 20 per cent below petroleum products. With these characteristics its efficient use is promoted in the National Greenhouse Strategy and State greenhouse strategies.

On balance we judge that greenhouse policies will provide an additional stimulus to gas demands in eastern and elsewhere in Australia over the period to 2020.

This additional stimulus appears to be built more into NIEIR projections than ABARE projections.

Other factors

24. Factors such as **rezoning, forced pipeline relocations** could affect remaining economic life and result in some network loss. **Unexpected, unspecified (contingency) factors** such as unexpectedly stringent environmental policies affecting natural gas production and use might reduce the economic life of GPU GasNet system elements. These factors could emerge at any time but are more likely to have an impact in distant periods (post 2020) when operating conditions are more difficult to predict at this time.

Thus a range of unforeseen, quite unexpected circumstances are likely to occur over a 40 year time span. For example, some market areas which seem to have a secure long term future could be abandoned through competitive pressures. Other major customers may come forward but are unlikely to be all in the same location as those that disappear. Or some emissions from natural gas using equipment could be deemed a health hazard and thereby force the loss of major markets through regulation and/or the high costs of removing the deemed health hazard emissions.

Estimates of remaining economic life should take account of such unspecified events occurring and affecting the life of network assets. Although difficult to estimate their probabilities of occurring it is very unlikely there is a zero probability that unforeseeable factors will not have an impact on asset lives in the very long (post-2020) term.

Analysis of factors

25. The analysis is conducted over three periods: 2001-2012, 2013-2025 and 2026-2040 for each system element: Longford-Dandenong (A), the South-West system (B), divided into two sub-elements, and the other elements (C) of the GasNet system.

26. As indicated above expected lives for transmission assets have been reviewed and re-estimated by GHD Ltd, and remaining technical life of the system is 28 years for element A, 57 years for element B (59 years for B (S/U) and 52 years for B (R)) and 37 years for element C.

27. For each asset element the remaining technical life is adjusted by economic factors to determine the remaining economic life (REL) of each asset element.

Analysis of factors reducing remaining economic life (REL) below RTL of each system element were based on probability analysis. This methodology provides a means of handling the uncertainty of future events, for example depletion of gas reserves, for which predictions cannot be definitive, but for which some data and knowledge are available.

Estimated probabilities of events occurring that would reduce remaining economic life may be used to quantify the impact of these events on remaining economic life.

Probabilities range from 0 (event will not occur) to 1.0 (event will certainly occur). The probability values of events occurring are estimated as objectively as possible from available data and the judgment of knowledgeable persons. In this study this approach is used to estimate probabilities of events occurring that could impact on the remaining economic life of GasNet's transmission network.

Application of this mode of analysis is given in the example below.

It is estimated that there is an 0.5 probability that the Gippsland Basin will be depleted by 2026 and that there is an 0.3 probability that element A will **not** be used for carriage of gas from other basins to markets along the route of element A.

The probability of element use as reserve depletion partly offsets the impact of reserves depletion on REL. The degree of offset depends on the probability of use or non-use. The higher the probability of non-use the greater the influence of reserves depletion on REL.

The impact of these probability estimates in element A is given by:

$$0.5 \times 0.3 = 0.15$$

The interpretation of this result is that the remaining economic life (REL) of element A in 2025 will be 15 per cent below the remaining technical life (RTL) by 2025.

28. The remaining economic life of element A – Longford to Melbourne – is largely dependent on the Gippsland Basin which has relatively large reserves but which over the next 20 years will be drawn on by Victorian, New South Wales and Tasmanian markets.

Depletion of the basin probabilities are estimated by considering ORR and AR basin reserves and NIEIR and ABARE demand projections.

This assessment of the situation indicates that Gippsland Basin reserves will be depleted between 2018 and 2030.

We estimate that:

(i) there is a 0 probability that Gippsland Basin reserves will be depleted by 2013;

(ii) a 0.5 probability that Gippsland Basin reserves will be depleted between 2013 and 2025; and

(iii) a 0.95 probability that Gippsland Basin reserves will be depleted between 2026 and 2040.

Combining probabilities of reserves depletion with a probability of 0.3 that Element A would **not** be used for some reverse flows (for example to regional power stations) as the Gippsland Basin depletes, the probabilities of the economic life of the pipeline element expiring in each period are estimated as:

(i)	2001-2012	0;
(ii)	2013-2025	0.5 x 0.3 = 0.15 = 15 per cent reduction in remaining technical life by 2025; and
(iii)	2026-2040	0.95 x 0.3 = 0.29 = 29 per cent reduction in remaining technical life.

29. Element B – the South West System – of the network will rely mainly on Otway (and to some extent Bass) Basin reserves to meet Western Victorian and Geelong regional markets and if reserves are found to be sufficient, part of the Melbourne region market.

At the moment estimates of reserves in these basins is particularly difficult because of the early stage of exploration and the recently announced discoveries at levels substantially above the official recoverable reserves (ORR). Accordingly there is a very high probability (close to 1.0) that actual reserves (AR) will be well above ORRs.

We estimate that:

(i) there is a 0.05 probability that Otway and Bass Basin reserves will be depleted by 2013;

(ii) an 0.5 probability that these basins will be depleted between 2013 and 2025; and

(iii) an 0.95 probability that the basins will be depleted between 2026 and 2040.

When the basins are depleted the regional markets are likely to be supplied from Western Australian/Northern Territory basins and most of the network would be used to transport this gas to the regions or to Melbourne. As the transmission system element is connected to the Pt Campbell Underground Storage facility which performs the essential task of stabilising system flows and adding to their security there is a low probability that the main part of the network (the South West pipeline) element will not be maintained.

However in this element, the Western Transmission pipeline from Pt Campbell to Portland will probably be negatively impacted to some extent by the proposed SEAGas pipeline from Pt Campbell to Adelaide. This pipeline, proposed to commence operation in 2004, now going through an environmental impact statement (EIS) process is a joint venture of Origin Energy and Australian National Power. The proposed pipeline parallels GasNet's Western system and could carry a majority of that pipeline's load, depending on the final design of, and demands on, the SEAGas pipeline. Thus the Western system part of Element B could be bypassed and become a stranded asset by 2005. Bypass possibilities, like reserve depletions considerations, decrease the REL of the system element.

The problem with treating element B homogenously is that the major part of the system, the South West (SW) portion, connects Melbourne with the Underground Storage (UGS) at Port Campbell. Given the system security importance of this SW/UGS system bypass of it is very unlikely.

Hence, the element B is treated at two sub-elements, element B (S/U) and B (rest):

(i) Element B (S/U). Element B (S/U) is treated as a sub-element where REL is reduced to some extent below RTL in recognition that over the long RTL of 59 years, demand and supply conditions and technological change could obviate the need for the UGS system.

Our estimate is these considerations would reduce the REL of element B (S/U) by about 10 per cent, that is to 6 years below the RTL of 59 years.

(ii) Element B (rest). Here reserve depletion probabilities (as above) are combined with bypass probabilities (that is bypass not like non-use reinforces the impact of reserves depletion on REL). RTL of Element B (rest) is 52 years.

Probabilities

Reserves depletion

2001 – 2012	0.05
2013 – 2025	0.50
2026 – 2040	0.95

Bypass probabilities

- 2001 – 2012 = 0.3
- 2013 – 2025 = 0.4
- 2026 – 2040 = 0.5

Combining probabilities give RTL reductions in each period for element B (rest) of:

- 2001 – 2012 = 0.05 x 0.3 = 1.5 per cent
- 2013 – 2025 = 0.50 x 0.4 = 20 per cent
- 2026 – 2040 = 0.95 x 0.5 = 47.5 per cent.

30. Element C – rest of GasNet system – covers a large and diverse area of north western, central and north eastern Victoria, mainly supplied at this time from the Gippsland Basin but also from the Cooper/Eromanga Basin. In the future the Otway and Bass Basins will also be used for supply to markets in this network element. As eastern Australian reserves are depleted virtually all the system could be supplied from Western Australian/Northern Territory basins and possibly CSM and the P-NG.

The element, however, is likely to be affected by competing pipelines which may be developed in the future.

Thus a new large capacity pipeline from the Moomba (South Australia) hub and linked to the high reserves WA/NT basins **might**, via laterals or the designed route, economically serve many load centres in northern and central Victoria. The probability of this occurring increases as south eastern reserves move towards depletion.

Taking the possibilities into account, the probabilities of the economic life of this network element expiring in each period are estimated as follows:

(i) 2001 – 2012 0.01 = 1 per cent;

(ii) 2013 – 2025 0.05 = 5 per cent; and

(iii) 2026 – 2040 0.15 = 15 per cent.

31. Factors such as rezoning, forced pipeline relocations and unexpected, unspecified (contingency) events could affect the remaining economic life of **all** network elements. It is difficult to claim there is a zero probability that unforeseeable factors will not have an impact on asset lives, particularly in the post-2020 period.

The estimate of the impact of these factors on asset lives in each period are:

(i) 2001 – 2012 0 (negligible);

(ii) 2013 – 2025 0.02 = 2 per cent reduction in remaining technical lives; and

(iii) 2026 – 2040 0.05 = 5 per cent reduction in remaining technical lives.

Remaining economic life of system elements – results

32. Results of the study analysis of the remaining economic life of Victorian transmission assets, based on RTL reductions, are presented in **Table E.1**.

Remaining economic life (REL) of system elements is arrived at by applying the reduction in remaining technical life (RTL) estimated by the factor analysis above to each network element in each analysis period. (Note that this analysis gives estimated average reductions of RTL in each period.)

Results of the study analysis of the remaining economic life of GasNet's transmission assets, based on RTL reductions, are presented in **Table E.1**.

Remaining economic life (REL) of system elements is arrived at by applying the reduction in remaining technical life (RTL) estimated by the factor analysis in Section 4.3 to each network element in each analysis period. (Note that this analysis gives estimated average reductions of RTL in each period.)

The interpretation of the results for element A (Longford to Melbourne) is that the remaining economic life (REL) is 21 years, giving an REL expiry date of 2022 compared with an RTL date of 2029.[2]

For element B (S/U) the REL is 51 years giving an expiry date of 2052 compared with an RTL date of 2060.

---

[2] Note that estimated REL for element A in the 2026-40 period is 19 years but is 24 years for the 2013-2025 period, indicating by this approach that REL is zero as the element enters the last period. Hence the 19 year estimate for the last period is only useful as a guide to the element's REL trends. The factor analysis thus indicates an REL of between 19 and 24 years; we have chosen 21 years and an expiry date of 2022.

For element B (rest) the REL is 27 years giving an expiry date of 2028 compared with an RTL date of 2054.

For element C (rest of system) the REL is 30 years giving an expiry date of 2031 compared with an RTL date of 2040.

As emphasised throughout the report, all factors impinging on remaining economic life of system elements are difficult to quantify and therefore the results are not presented as being definitive.

The estimated reduction in remaining technical life from the factor analysis is adjusted (reduced) to take into account that factors may be coincident, that is may not be additive. For example, stringent environmental policies may coincide with the reserves depletion and impacts on a similar part of the network.

The estimate of REL in Table E.1 is based on factor probability analysis being used to estimate the reduction of RTL of the network elements.

A **second** approach to estimation of REL could be based on estimates of eastern Australian reserves depletion at a 0.95 probability level, subject to any RTL constraint.

For element A (Longford to Melbourne) we estimate that this date (for Gippsland Basin reserves) would be around 2035 giving an REL of 28 years (RTL constraint) for the element.

For element B (S/U) operation on more remote reserves when eastern Australian reserves are depleted gives an REL which is similar to the RTL of 59 years.

For element B (R) given the significant uncertainty of Otway/Bass Basin reserves we estimate this date to be around 2040. On the other hand this element could operate on more remote reserves giving an REL similar to the RTL of 52 years.

For element C (rest of the system) reserve considerations indicate that most of the system C would continue to operate on more remote reserves when eastern Australian reserves were depleted. Under this approach for this element REL is similar to the RTL of 37 years.

This approach ignores the probabilities that reserves could be depleted earlier, other reserves could be used, back haul is uncertain, bypass is a possibility and that other factors could affect REL.

A **third** approach is to conclude that the analysis of factors in the report indicate that they will not have a significant impact on the REL of the elements given that total gas reserves (eastern-Australia, CSM, WA/NT and P-NG) available to Victorian markets will last until about 2060. In this situation the REL of each element would be only constrained by RTL.

This approach ignores the impacts of eastern-Australian reserves depletion and other factors such as bypass on the REL of system elements.

Table E.1 Estimates of remaining economic lives of system elements based on RTL reductions

Time period	2001 – 2012				2013 – 2025				2026 – 2040			
System element	A	B (S/U)	B (R)	C	A	B (S/U)	B (R)	C	A	B (S/U)	B (R)	C
Remaining technical life (RTL) years from 2001	**28**	**59**	**52**	**37**	**28**	**59**	**52**	**37**	**28**	**59**	**52**	**37**
Factor												
Reserves/demands (per cent reduction of RTL)	0	0	1.5	1	15	0	20	5	29	10[1]	47.5	15
Other factors (per cent reduction of RTL)	0	0	0	0	2	2	2	2	5	5	5	5
Total reduction of RTL	0	0	1.5	1	17	2	22	7	34	15	52.5	20
Adjustment for coincidence of factors	10% reduction	10% reduction	10% reduction	10% reduction	10% reduction	10% reduction	10% reduction	10% reduction	10% reduction	10% reduction	10% reduction	10% reduction
Adjusted reduction of RTL (per cent)	0	0	1.35	0.9	15.3	1.8	19.8	6.3	30.6	13.5	47.25	18.0
Estimated REL	28	0	51	37	24	58	42	35	19	51	27	30

Note: 1. Special factors effecting element B (S/U).

33. **Conclusions**

Each approach has some merit but we tend to favour the first, that is based on RTL reduction, but with recognition of the other approaches impacts on REL, resulting in recommended RELs as follows:

Element A	23 years – the economic life expiry date is 2024
Element B (S/U)	52 years – the economic life expiry date is 2054
Element B (R)	30 years – the economic life expiry date is 2031
Element C	32 years – the economic life expiry date is 2033

Regulatory and legal factors

34. The valuation of the long lived transmission assets in the energy sector has recently become a significant issue for the owners of the transmission assets. Until quite recently, these assets were government owned and operated. The privatisation and transfer of these assets into regulated asset bases under the Gas Codes and the National Electricity Code raised initial issues about the valuations and the valuation methodologies of jurisdictional regulators. The ACCC has developed Draft Regulatory Principles under the National Electricity Code in the interest of regulatory transparency and consistency. There are also recent major income tax changes affecting the return of capital for transmission asset owners following the abolition of accelerated depreciation. The new taxation regime permits self-assessment of the effective life of assets as an alternative to using the statutory effective life table.

35. Section 6 of this Report provides general background and description of the regulatory regime and the new taxation regime.

36. Analysis is performed from two principal perspectives. The first is the methodological basis upon which the Capital Bases were determined for the Access Arrangement. We comment on this methodology and the contribution that the Saturn Report made to establishing the depreciation profile for the initial regulatory period expiring 31 December 2002. We note in particular that the remaining effective lives of the transmission assets for the Principal Transmission System and the Western Transmission System, as thereby estimated, were accepted by the ACCC and, implicitly, the methodology adopted in the Saturn Report, was also accepted.

37. We have also analysed the decisions of the ACCC as Regulator under the National Electricity Code, as well as decisions in Access Arrangements in other states, including those of OffGAR in Western Australia, to illustrate the approach taken to establishing the valuation of initial Capital Bases, depreciation profiles and effective lives for electricity and gas transmission assets. Those case studies indicate that the ACCC has a stated preference for consistency in the determination of asset lives but it has significantly departed from that precept. We have noted that, across both gas and electricity valuations, there are assumptions, but little evidence, about standard industry lives for transmission assets. In New South Wales, for example, AGL and EAGL estimated the effective lives of transmission pipeline assets at between 60-80 years. In the latter case, the ACCC adopted straight-line depreciation on an effective life of 50 years. In South Australia, the two Access Arrangements based indicate 80 years' effective life. A single Access Arrangement provides the example of an 80-year effective life with a kinked depreciation schedule to allow for risk of stranding or reduced revenue due to the expiry of foundation contracts. In Western Australia, the Regulator regularly adopts a 70-year effective life and presumes this is the industry norm. The significant Snowy Mountain Hydro-Electric Authority case, and the Queensland revenue cap decision, highlight the decision of the ACCC to accept

independent valuations relying upon overseas effective life estimates in preference to consistent lower economic life estimates by New South Wales Treasury, the SMHEA and Transgrid. Overall these cases indicate that the ACCC does not adopt a prescriptive view about asset life, that it prefers in principle a consistent approach but in practice will tailor the effective life and depreciation profile for assets to accommodate an overall regulatory outcome.

38. We have also analysed the provisions of the Code for review of the asset lives on reset for the next regulatory period. We have contrasted the stated intention of the ACCC to apply a mechanistic interpretation of the Code for valuing the Asset Base on reset with more general provisions in the Code requiring maximal adjustment of the depreciation profile for changes in the economic life of relevant assets. In addition, we have highlighted provisions of the Code that require the general risk profile for the service provider to be taken into account in determining the Tariff Revenue.

39. The ACCC has acknowledged it has a learning curve in the development of its role as the Regulator of both gas and electricity transmission assets. In particular, it has stated that it expects to amend its Draft Regulatory Principles in light of its experience. There is no precedent for reset because the next reset is the first. It is therefore difficult to predict the weight which the ACCC will give to individual factors in deciding tariff revenues on reset.

1. Introduction

In setting tariffs for use of gas transmission networks the allowable depreciation rate is a critical element. The more rapidly an asset depreciates the greater the initial revenue, *ceteris paribus,* required to deliver a target or regulated rate of return from it and conversely the less rapidly an asset depreciates the lower the revenue, *ceteris paribus,* required to result in a given rate of return.

In setting depreciation rates the starting point is generally the technical (design or expected physical) life of an asset. For a new asset this is defined in terms of the expected technical life when the asset is installed or commissioned. But for an existing asset the remaining technical life is the appropriate measure of technical life. In the case of a new asset the remaining technical life is its design life at the time of installation.

As a transmission network comprises a range of assets of different vintages, there will not be a single remaining technical life; instead there will be a range of remaining technical lives. For some assets their refurbishment, for example by plastic insert lining, will extend remaining life while for others refurbishment and maintenance may be uneconomic or it may be physically difficult to ascertain their condition. For example the so-called Lurgi line from the Latrobe Valley which comprises about 10 per cent of the transmission capacity from Gippsland to Melbourne is not amenable to “pigging” (internal inspection) to determine its physical condition. Hence it may fail prematurely.

The technical (design or expected physical life) of an asset is often, however, not a definitive measure of how long an asset is expected to contribute a satisfactory revenue stream as it may become commercially marginal or sub-marginal before its technical life is reached. Safety concern would be one such reason, for example corrosive soil conditions requiring pipeline replacement with a more corrosion resistant material. Economic factors may also render an asset commercially unviable before its technical life was reached. Even if an asset is well maintained and quite capable of producing goods or services for which it was designed, when it can no longer contribute to financial targets of the owning operating entity its economic life is effectively over. Hence in estimating effective lives of assets it is necessary to look beyond physical/technical/design life and estimate the probability that one or more of technical, economic or commercial factors will result in retirement of an asset before the technical is reached. For example, an asset’s functions may be superseded by new assets (similar or dissimilar) to such an extent that the net revenue (revenue-capital expenses-operating costs) stream from a new asset is greater than the future revenue stream of the existing asset. New later model computers are a prime example of this situation, it often being economic to replace perfectly functioning computers after 3-5 years.

Although a situation similar to computers is very unlikely in the case of gas (or electricity) transmission assets other factors may, with varying probability (degrees of uncertainty) diminish the economic life below the technical life of these assets. A regulatory regime which recognises the important economic role of technically long lived assets and the uncertainties they face over their **potentially** long life will, *ceteris paribus*, attract more investment in these assets. For a major factor of production such as natural gas the attraction of investment in new transmission assets and in maintenance of existing transmission assets is vital for enhancing efficiency of energy and overall economic systems through provision of system security and increased competition.

In summary the remaining economic lives of GasNet’s gas transmission system elements are the appropriate basis for establishing the applicable depreciation rates.

One factor in determining economic life of gas transmission assets is the life of the natural gas reserves which underlie the commercial rationale for the asset: the carriage of gas to markets. The life of gas reserves depends on the quantum of those reserves that can be economically recoverable and the market demands for those reserves. Projections of demands can be prepared based on current and likely future market conditions. However market conditions will change over the life of such technically long lived assets, for example through competition from other energy sources. The competitiveness of other energy sources, for example renewable energy types, may be enhanced by government policies in the greenhouse field.

Demands for the product the asset serves, for example gas in the case of a gas transmission pipeline, may decrease to such an extent that demand may be commercially met from another gas or other energy source. On the other hand, gas demands may increase to such an extent that reserves serviced by the pipeline are depleted more quickly. For these reasons careful assessment of market demand is required to estimate the expected remaining economic life.

Reserves and demands on reserves – an example

A pipeline with a technical life of 50 years may be constructed to carry 100 PJ to markets. At an average annual draw on the reserves of 5 PJ the pipeline would have an economic life of 20 years and one of 10 years at an average annual demand on the reserves of 10 PJ.

In both of the above cases economic life is less than technical life.

At reserves of 300 PJ and demand on reserves of 6 PJ per year, economic life = technical life = 50 years.

In assessing the commercial viability of existing and new assets these and other factors must be taken into account by asset owners (or prospective owners) and regulatory authorities to assess the remaining economic life of assets and therefore the appropriate depreciation rate to be applied to assets.

In this report the factors affecting the commercial environment of GasNet's transmission assets are assessed as to their probable impact on the remaining economic life of those assets, along with a review and analysis of the trends in regulatory regimes applicable to the depreciation and other treatment of such assets. The transmission assets can be divided into three elements:

Element A	Longford to Melbourne;
Element B	South West System divided into two sub-elements:
	Element B (S/U) – the South West portion including the Underground Storage System; and
	Element B (R) – rest of the South West System;
Element C	Rest of system.

2. Technical life of GasNet's gas transmission assets

2.1 Technical life (TL)

The TL represents the assessment of the total useful life that can be expected when the assets are initially installed based on the quality of materials used, environmental conditions under which the asset operates and in the case of transmission pipes the temperature and pressure at which the gas is being carried through the network of pipes.

GHD has reviewed current industry standards and concluded that the assessment and experience of GasNet and its predecessors with regards to its particular pipes remains valid. As stated in the GHD 1997 report "there are few benchmarks for pipelines operating under identical conditions and maintenance regimes" (section 5.2) and therefore concluded that management assessment of 60 years based on historical experience, although conservative, was valid.

Based on this specific experience of the 'insitu' pipes under review the GHD 1997 report adopted a technical life of 60 years for the pipeline assets.

On review GHD has concluded that no technological or major physical events have occurred that substantially impact on the TL assessment derived in the 1997 valuations. It is therefore recommended that the TL of 60 years be retained.

2.2 Remaining technical life

By the application of the technical life to the GasNet Transmission Network the remaining technical life of each asset has been calculated using the formula: design life less life expired to date = remaining life where life expired to date = report date less date installed and commissioned.

The TL of 60 years has been applied to the GasNet pipe assets to determine the weighted average remaining life by asset grouping: element A, element B and element C.

Element A (Longford to Melbourne)	28 years
Element B (total South West System)	55 years
Element B (S/U)	59 years
Element B (R)	52 years
Element C (Rest of system)	37 years

Refer to **Appendix A** for a detailed analysis of GasNet's transmission assets.

2.3 Asset working environment

In perfect conditions it can be expected that like assets will have the same technical life. However, when placed in differing environments the technical lives can vary considerably and the durability of all assets will be directly affected by the quality and frequency of maintenance programs.

For those assets located underground, aggressive ground conditions or ground movement can have a significant impact. For those assets such as compressor stations that are located above ground their exposure to sun, wind and moisture can have a significant corrosive impact on technical life. For those located near the sea, or in areas of stray currents, effective life will also suffer (for example concerns of the impact of the proposed Basslink electricity link between Tasmania and Victoria). Therefore, consideration of regional influences must be made when comparing the anticipated effective life of similar assets across businesses and regions.

External stresses, particularly those due to largely unpredictable events, can have a drastic or cumulative negative effect on effective life. For example:

- ground movement caused by adjacent construction;
- adverse weather conditions;
- corrosion due to stray currents from electricity lines and from chemical sources; and
- geological pressures (earth tremors).

Again, regional factors must be considered in terms of the likelihood of events that cause external stress and the consequent reduction in effective life.

3. Economic and institutional factors impacting on the remaining economic life of GasNet's transmission assets

3.1 Introduction

As indicated above, even though the asset may be technically functioning well when it can no longer generate satisfactory net returns its economic life is effectively over. Accordingly it has reached the end of its effective life. Remaining economic life will be determined by technical (discussed in Section 2 above), economic/commercial and institutional factors. Economic aspects include supply constraints, demand trends, demographics and industrial mix trends. Commercial factors include heightened competition and pressures from stakeholders, including customers, shareholders and regulators. Institutional factors include competition, energy and environmental policies which impact on the commercial and regulatory regime in which the assets function.

Economic/commercial and institutional factors affecting the remaining economic lives of GPU GasNet's gas transmission assets are discussed below under the headings of natural gas reserves, natural gas demands, institutional factors and other factors.

3.2 Natural gas reserves impacting on GasNet transmission assets

The gas reserves which a pipeline carries to markets are of crucial importance to the pipeline's remaining economic life as the carriage of reserves to market is the reason for the pipeline's existence. Remaining life of reserves has two main determinants:

(iii) quantity of reserves; and

(iv) demands on those reserves.

Estimates of economically recoverable reserves are based on proved, probable and likely commercial reserves. In addition estimates are made of undiscovered, based on probability of reserves being proven given the geological characteristics of the region. As undiscovered reserve estimates are very uncertain, recoverable reserve estimates generally only include proved, probable and other likely reserves which have not yet been declared commercially viable. These estimates are prepared for each geological basin and for fields within those basins.[3]

Different reserves affect different transmission assets. For example the main transmission link between Longford and Melbourne depends on Gippsland Basin reserves and the South West element depends mainly on Gippsland, Otway and Bass Basin reserves, and the rest of the system the above basins and other basins connected to the Victorian system. Accordingly in this report analysis is conducted on three system elements:

- the Longford to Melbourne transmission element;
- the South West transmission element divided into two sub-elements:
    - Element B (S/U); and

[3] Notes on reserve definitions and estimates are contained in **Appendix B.**

- Element B (R); and
- the rest of the transmission system.

When reserves are depleted there may be use for the pipelines for reverse haulage of gas from other basins to regional markets such as Cooper/Eromanga (northern South Australia, Northern Territory and south-west Queensland, but which has limited reserves to service South Australian, New South Wales and Queensland markets) but more importantly as yet unconnected Western Australian/Northern Territory and Papua New Guinea basins. On the other hand new pipelines might lead to bypass of system segments and thus render these segments non-commercially viable.

The current basin by basin official recoverable reserve (ORR) situation in Australia is given in **Table 1**[4] and the current picture of transmission pipelines, reserves and basins is presented in **Chart 1**. Note that currently the Amadeus and Western Australian basins are not yet connected to eastern Australian markets. Also note that these northern (WA/NT) basins comprise about 80 per cent of total Australian reserves. If these reserves were connected to eastern Australia they would ensure ample supplies in the region until about 2060 given potential reserve and demand increases (very difficult to predict post-2020). However, the gas would likely be higher priced than current eastern Australian gas to cover the higher transmission costs.

It should be noted that the official recoverable reserve figures are not universally accepted and many analysts believe that these estimates are conservative. For example they point to recent company announcements that Otway Basin reserves from recently discovered fields may be in the 3,000-4,000 PJ range (official recoverable reserves of 526 PJ) and in the 2,000-3,000 PJ range for the Bass Basin (official recoverable reserves of 376 PJ).[5] Both these basins have lightly explored compared with the Gippsland Basin. And new reserve additions continue to be made to the Gippsland and Cooper/Eromanga basins. Thus, actual reserves (AR) in south east Australian basins are likely to be above the official reserve estimates and could total around 25,000 PJ.

Nevertheless, it is important to base the current analysis predominantly on official recoverable reserves as possible reserve additions may not eventuate; possible reserve additions should, however, be noted and their implications analysed.

The withdrawals picture from the eastern Australian basins is changing rapidly with new pipelines being built to meet growing demands for gas (see below), particularly for electricity generation, in a competitive environment.

---

4 Latest available official reserve estimates. These reserve estimates do not include coal seam methane (CSM) which occurs in black coal deposits and which is being tapped in small quantities (about 20 PJ per year). An AGA paper prepared by Dr George Webb, *National Supply and Demand Outlook for Gas*, June 2001, estimated about 1,800 PJ of eastern Australian CSM might become available by 2029-30, with a total of about 250 PJ being supplied by 2015-16.

5 The 1993 Bureau of Resource Sciences (nor the Australian Geological Service Organisation, AGSO), the latest report to publish such figures, put undiscovered resources in these two basins, on limited survey and exploration data, as approximately 1,900 PJ and 750 PJ respectively at the 0.5 probability level. No decision has yet been taken on release of updated undiscovered resource estimates in the imminent AGSO 2001 report.

Chart 1

The main existing and new south-east Australian pipelines and their capacities are set out below, by basin.

Table 1 Natural gas production and recoverable reserves by basin, 1999-2000

Basin	Recoverable reserves as at 1 January 2000[a] (PJ)	Production 1999-2000 (PJ)	Reserves to production ratio[b] (years)
Adavale (Qld.)	13	0.7	18
Amadeus (NT, WA and SA)	488	19.3	25
Bass (Vic., Tas.)	376	0.0	na
Bonaparte (WA, NT)	24 897	0.0	na
Bowen/Surat (Qld.)	218	27.4	8
Browse (WA)	20 719	0.0	na
Carnarvon (WA)	67 289	718.4	94
Cooper/Eromanga (Qld. SA)	4 898	232.4	21
Gippsland (Vic.)	8 390	202.2	41
Otway (Vic., SA)	526	8.1	65
Perth (WA)	112	10.1	11
Total	**127 928**	**1 218.7**	**105**

Notes: a Most recent figures available.
b Reserves divided by **current** production.
Source: Australian Gas Association (AGA), Gas Statistics, September 2001 from AGSO-*Geoscience Australia*, preliminary data.
ABARE 2001, *Australian Mineral Statistics*, Canberra, March Quarter.

Demands on south east Australian basins

Basins and transmission pipelines	**Capacities**
Gippsland Basin (ORR = 8,000 PJ, 1 January 2002)	
Longford to Melbourne, GPU GasNet	250 PJ per year
Longford to Sydney (Wilton), Eastern Gas Pipeline (EGP), Duke	110 PJ per year
Longford to Tasmania, Bell Bay, Gaslink, Duke, by 2003	40 PJ per year
Orbost to EGP, based on Patricia/Balleen fields, OMV, by 2004 (included in EGP capacity flow)	(10 PJ per year)
Total	**400 PJ per year**

At an average draw on the Basin of 400 PJ per year (to 2020) post 2002 official recoverable reserves would be depleted in about 20 years (by 2021).

Otway Basin (ORR = 500 PJ, 1 January 2002)

Port Campbell to Melbourne, GPU GasNet	25 PJ per year
Port Campbell to Adelaide	
SEAGas (Origin, ANP, SAMAG), 2003	45 PJ per year
Duke/GasNet	? PJ per year
(the SEAGas and Duke/GasNet pipelines are assumed to be mutually exclusive)	
Total	**70 PJ per year**

At an average draw on the Basin of 70 PJ per year (to 2010) post 2003 official recoverable reserves would be depleted by 2010.

Bass Basin (ORR = 376 PJ, 1 January 2002)

SEAGas to Adelaide from Thylacine (additional to Otway estimates above)	20 PJ per year
Bass Gas (Origin, *et. al*.) from Yolla	20 PJ per year
Total	**40 PJ per year**

At an average draw on the Basin of 50 PJ per year post 2003 official recoverable reserves would be depleted by 2010.

Cooper/Eromanga Basin (ORR @ 4,400 PJ, 1 January 2002)

Moomba to Adelaide	110 PJ per year
Moomba to Sydney	140 PJ per year
Moomba to Wagga to Melbourne (EAPL)	35 PJ per year
Moomba to Jackson/Wallumbilla to Queensland	100 PJ per year
Total	**385 PJ per year**

At an average draw on the Basin of 385 PJ per year post 2003 (to 2015) official recoverable reserves would be depleted in about 14 years (by 2015) but new economic supply to Queensland from non-EA sources is, in practice, likely to extend basin depletion to SE Australian markets.

With allowance for production from smaller basins, coal seam methane (CSM, not included in ORR estimates) the above and smaller pipelines, with enhancements, would carry about 15,000 PJ over 1999-00 to 2014-15. Official recoverable reserves in eastern Australian basins are now about 15,000 PJ (including CSM).

It should be noted that the above data refers to current and projected pipeline capacity to about 2010 and not to projected demands over 2001-02 to 2019-20. Thus potential reserves must be matched with demand projections in the regions. However, these potential withdrawals suggest that based on official recoverable reserves these eastern Australian basins would be depleted in about 15 years.

Based on estimates of actual reserves (about 25,000 PJ), the basins would be depleted in about 25 years. As the reserves move towards depletion it is expected that supplies would come from Western Australia, Northern Territory, Papua New Guinea and coal seam methane (CSM)[6] in New South Wales and Queensland. Currently there are proposals to connect WA/NT and PNG basins to eastern Australia as early as 2005, but no firm commitments for the necessary connections have been made.

This crucial issue is revisited and estimates refined below on a system element basis after consideration of gas demand forecasts.

3.3 Natural gas demands

3.3.1 Projections: forecasts, drivers, discussion

Natural gas demand projections by state and sector are prepared periodically (every 1-3 years) by the Australian Bureau of Agricultural and Resource Economics (ABARE) and the National Institute of Economic and Industry Research (NIEIR).

The most recently published NIEIR forecast is presented in **Table 2** and that for ABARE in **Table 3**. Forecasts depend on economic growth, economic structural change (for example in the food and mineral processing industries) and relative prices of end-use energy in competing sectors. For example electricity versus gas in space and water heating and gas versus coal in electricity production.

The new ABARE (October 2001) projections are below those prepared by ABARE in 1999 and about 17 per cent below those prepared by NIEIR in 1999, for the period 2000-01 to 2014-15.

The 1999 NIEIR forecast for eastern Australia totals 722.1 PJ in 2004-05 and 1,162.4 PJ in 2014-15, while the ABARE forecasts are 626.3 PJ and 901.4 PJ, respectively.

Tables 2 and 3 show some significant variations between ABARE and NIEIR forecasts which are mainly due to differing views on the use of gas for electricity generation, particularly in Queensland. In this fuel use sector there is considerable debate and divergence of opinion on the respective roles of gas and coal and, to a lesser extent, the role of renewables over the next 20 years.

Note that after the 2001 ABARE report was completed Queensland announced a program to boost the use of gas in electricity generation by 2005.

6 Small amounts of CSM are currently being used.

Table 2 Natural gas consumption by sector and state to 2014-15

	1996-97 (PJ)	2004-05 (PJ)	2014-15 (PJ)	Compound growth rate 1997-2015 (per cent)
New South Wales				
Residential	17.2	23.4	29.3	3.0
Commercial	14.8	22.0	32.1	4.4
Industrial	83.7	98.3	116.1	1.8
Electricity	10.7	15.0	88.4	12.5
NGV	0.4	3.3	9.7	19.1
Other	3.1	3.7	5.8	3.5
Total	**129.9**	**165.7**	**281.4**	**4.4**
Victoria				
Residential	78.9	96.2	108.5	1.8
Commercial	23.4	30.6	38.4	2.8
Industrial	116.2	138.8	158.0	1.7
Electricity	13.0	15.2	38.4	6.2
NGV	0.5	3.8	9.3	17.4
Other	7.1	8.4	9.3	1.5
Total	**238.5**	**293.0**	**361.9**	**2.3**
Queensland				
Residential	1.1	2.4	3.0	5.5
Commercial	1.3	2.1	3.5	5.8
Industrial	41.4	73.7	138.0	6.9
Electricity	2.3	90.7	178.1	27.3
NGV	0.2	1.7	4.4	20.6
Other	0.8	2.4	4.1	9.2
Total	**47.1**	**173.0**	**331.1**	**11.4**
South Australia				
Residential	7.5	8.6	9.4	1.2
Commercial	5.4	6.8	9.2	3.0
Industrial	50.7	54.0	61.5	1.1
Electricity	34.3	53.9	69.2	4.0
NGV	0.2	0.9	1.7	13.2
Other	1.4	1.8	2.0	1.9
Total	**99.5**	**126.0**	**153.0**	**2.4**
Western Australia				
Residential	8.1	11.1	13.8	3.0
Commercial	9.6	6.3	8.9	-0.4
Industrial	195.9	250.1	344.4	3.2
Electricity	69.5	119.3	140.5	4.0
NGV	0.1	1.6	4.0	22.7
Other	0.9	1.2	1.6	2.9
Total	**284.1**	**389.6**	**513.2**	**3.3**
Northern Territory				
Residential	0.0	0.1	0.1	6.3
Commercial	0.2	0.3	0.3	3.1
Industrial	0.1	0.1	0.2	4.4
Electricity	18.0	23.1	30.6	3.0
NGV	0.1	0.2	0.4	9.9
Other	0.0	0.0	0.0	0.0
Total	**18.4**	**23.8**	**31.7**	**3.1**
Tasmania – total	**0**	**15**	**35**	**–**

Notes:
1. Commercial is the sum of construction, wholesale and retail trade, transport storage and communication (excluding NGV), finance, property and business services and public administration, defence and community services.
2. Comprises agriculture, mining and manufacturing.
3. Electricity refers only to electricity generation.
4. Other includes gas production and distribution and water, sewerage and drainage.

Source: *Natural gas consumption in Australia to 2015 – prospects by state, industry and sector*, NIEIR for AGA.

Table 3 2001 ABARE projections of eastern Australian gas demands			
	1998-99	2004-05	2014-15
New South Wales	133.1	151.3	198.4
(electricity)	(14.8)	(20.1)	(36.4)
Queensland	62.1	95.6	157.8
(electricity)	(18.6)	(28.2)	(64.1)
Victoria	219.0	259.7	345.6
(electricity)	(27.4)	(39.0)	(70.6)
South Australia	109.8	142.3	176.9
(electricity)	(72.4)	(94.5)	(117.9)
Tasmania	0	7.4	22.7
(electricity)	(0)	(2.4)	(8.1)
Totals	**524.0**	**626.3**	**901.4**

Source: ABARE energy projections, ABARE Research Report 01.11, October 2001.

3.3.2 Implications for reserves and pipelines

The NIEIR forecast projects about 14,000 PJ of demand over 1999-00 to 2014-15 against official recoverable reserves (including AGA's CSM supply estimate of 250 PJ by 2015) of about 15,000 PJ at that time in eastern Australia. In 2014-15 NIEIR's projected demand in eastern Australia is about 1,160 PJ suggesting depletion of eastern Australian basis by 2015-16. This compares with the AGA (Webb, 2001) estimate (based on 1999 ABARE projections) of projected demand of 13,226 PJ, and official recoverable reserves of about 15,000 PJ (including CSM) over 1999-00 to 2014-15. Allowing for use in 2015-17 of about 2,000 PJ (average of NIEIR and ABARE estimates) this puts depletion of eastern Australian official recoverable reserves in about 2016-17, that is a year later than NIEIR. On the basis of ABARE's 2001 demand projections for eastern Australia (for the period about 10 per cent below their 1999 projections on which AGA analysis was based), depletion of Eastern Basin reserves would occur in about 2019-20.

Basin by basin analysis of reserves depletion may be estimated based on demand (withdrawal) projections and reserve (official, likely, actual) estimates.

This analysis is, it must be emphasised, subject to the informed views of each analyst of factors and events which may operate far into the future (beyond 20 years).

Our preliminary analysis is set out below (note that detailed analysis is beyond the scope of this study). The analysis is based on projected demands (average of NIEIR and ABARE) on each basin to 2019-20 extrapolated by us to the 2030s, ORRs and our AR estimates.

Depletion date estimates for the three "Victorian" basins (Gippsland, Otway, Bass) are very difficult, not only because of reserve and demand uncertainties, but also because of uncertainties of supplies to South Australia, New South Wales and Queensland from other eastern Australian basins (mainly Cooper/Eromanga) and remote basins (WA/NT and PN-G). The estimates presented in Table 4 assumes that Queensland begins to be supplied from these remote basins before 2010, thereby analysing productive life of these basins to extend beyond 2017 (ORR) and 2026 (AR). As stated in Table note 3, in an inter-connected system all basins would tend to be depleted at the same time with some variation due to regional delivered gas economics.

Table 4 Estimates of Gippsland, Otway and Bass basin depletions

Basin	Withdrawals[1] 2002-2020	Withdrawals[1] 2020-2040	Official reserves[2]	Actual reserves[3]
Gippsland	8,000 PJ	4,000 PJ	8,000 PJ	12,000 PJ
Depletion date			2019	2027
Otway	2,000 PJ	2,000 PJ	500 PJ	3,500 PJ
Depletion date			2010	2030
Bass	1,000 PJ	2,000 PJ	376 PJ	2,500 PJ
Depletion date			2012	2029
Cooper/Eromanga and minor basins	6,000 PJ	1,500 PJ	4,400 PJ	7,000 PJ
Depletion date			2014	2024

Notes:
1. Extrapolation of average of ABARE and NIEIR demand projections and Saturn estimates of basin withdrawals to meet these demands; post-2020, potential withdrawals not realised due to resource depletion.
2. Official (2001 AGSO preliminary) reserves.
3. Saturn estimates of ultimately recoverable reserves at the 0.50 probability level, that is some estimates go well beyond these levels, for example some industry sources indicate +15,000 PJ in the Gippsland Basin. In an inter-connected system one would expect similar depletion dates.

The implications for GasNet system elements is analysed in Section 3.4.4 below. Reserve and demand drivers are discussed in Sections 3.3.3 and 3.3.4 below.

3.3.3 Reserve drivers

Decreases in reserves are very unlikely: lower real gas prices compared with alternatives would slow reserves development, as would future technical work which showed official reserve estimates were too optimistic. Both these conditions are considered very unlikely.

It is more likely, however, that as indicated above actual reserves will prove to be higher than official reserves as a result of increased exploration for gas, better exploration techniques which would likely result in improved exploration success, and higher real gas prices which would result in a greater exploration effort and the viability of higher cost reserves.

3.3.4 Demand drivers

Increases in demand

Increases in demands above those projected could come from higher economic growth rates, lower relative (to other energy sources) gas prices, technological change favouring natural gas usage and policy changes (see below). Higher economic growth rates than those assumed by forecasters are considered unlikely, but lower gas prices relative to coal and petroleum products, could result from more stringent greenhouse policies (see below).

Technological change favouring gas usage could come from a range of technologies including micro gas generators (<1 MW), fuel cells, cogeneration, continued improvement in combined cycle gas turbines (all the foregoing are electricity and heat generation technologies), gas cooling, gas use in transport using compressed or liquefied natural gas and continued improvement in the efficiency of end-use gas technologies.

These technological change possibilities based on current expectations for their utilisation are considered to have been adequately taken into account in the NIEIR and ABARE projections.

Decreases in demand

Decreases in demand below those projected could come from lower economic growth rates, higher relative gas prices and technological change favouring energy sources other than natural gas.

Higher relative gas prices could come from greater competition from renewable energy sources (particularly in electricity generation, for example wind, biomass) and from reliance on higher cost (at point of use) gas reserves, for example WA/NT and CSM reserves.

Technological change favouring competitors to gas could come from electro-technologies and from renewable sources.

Electro-technologies comprise a range of technologies which use electricity at levels of efficiency which can offset the price advantage of gas (in applications where gas does not need to be converted into electricity).

These electro-technologies represent the most serious competitive threat to gas demands from electricity and hence to natural gas infrastructure in the 2002-2020 period due to their higher energy efficiencies and contributions to higher overall process productivity. Post-2010 renewables could pose a competitive threat as their prices drop relative to gas and gas generated electricity. The main technologies posing a competitive threat to natural gas are as follows.

- **Heat pumps**. Equipment based on the heat pump principle can produce heat requirements at very high levels of efficiency. Heat pumps convert low grade sources of energy such as ambient temperatures and waste heat into higher grade energy and can thereby achieve efficiencies of well over 100 per cent. That is, from each unit of energy input into a heat pump, through the upgrading of low grade energy sources, the heat pump can produce more than one unit of useful energy output for each unit of energy input. Heat pumps can be used for residential water heating, residential space heating and cooling (units capable of heating and cooling are known in Australia as split systems) and a wide range of heating and drying processes in the industrial and commercial sectors. Because heat pumps extract energy from heat sources and use this extracted energy for heating, it is possible to use them in a reverse mode for space cooling. Therefore in the residential sector a heat pump can cater to both heating and cooling demands. In restaurants (commercial sector), overheated cooking areas can be cooled by the heat pump and the extracted heat used to produce hot water for the restaurant operations.

  An electrical heat pump, capable of producing 2 units of energy output for each unit of input (200 per cent efficiency), would, if it replaced a natural gas appliance producing 0.8 units of output for each unit of input (80 per cent efficiency), give electricity an efficiency 2.5 times that of natural gas. Therefore, **if** natural gas cost $6 per gigajoule, and electricity $15 per gigajoule (or about 5 cents per kWh), electricity would just be competitive with gas depending on the relative costs of the heat pumps and natural gas equipment involved.

  Electrical heat pumps have undergone and continue to undergo significant development and commercialisation over the past fifteen years. Due to these changes they could penetrate many heating, drying and cooling markets over the next ten to fifteen years. Some evidence is emerging that split systems/heat pumps, which are achieving increasing market penetration are beginning to impact gas space heating demands in Victoria. **Gas heat pumps technology**, however, is also being significantly improved and **could** be competitive with electric systems within the next 5-10 years.

- **Microwave technology**. This technology is inherently more efficient than heat processes for drying, cooking, etc. because the energy required for achieving the desired result of these processes can be delivered much more precisely where, when and in the quantities required. Like heat pumps, microwave equipment is penetrating a range of energy use markets and has the potential to markedly increase its market penetration.

- **Other electro-technologies** with potential for competing with natural gas through increased energy efficiencies and productivity improvement include plasma arcs (for high temperature industrial processes), induction heating, membrane separation, freeze concentration, infra-red heating, ultra-violet curing and radio frequency drying.

- In the low temperature heating (water, space process) markets, **solar energy** could become competitive with gas (and electricity) and in electricity generation (solar thermal, photovoltaics) partly through technological improvement, but mainly through government policy initiatives to address environmental (particularly greenhouse) concerns. Other renewables (wind, geothermal and biomass) could also become competitive with gas under similar conditions. Renewable competitiveness is particularly likely to develop in the 2010-2015 period. The federal Mandated Renewable Electricity Target (MRET) which mandates an additional 9,500 GWh of renewable electricity by 2010 is providing competition for gas (and other fossil fuels) in electricity generation and water heating (most solar hot water systems are eligible).

Overall we judge that there will be no net impact on demand projections of the demand drivers considered above in this section.

If Western Australia/Northern Territory gas and CSM is introduced into eastern Australian markets, relative gas prices are likely to rise and dampen gas demand growth but to a level which is unlikely to impact on the remaining economic life of GPU GasNet's transmission assets.

Higher relative gas prices and the other demand drivers assessed above are much more likely to affect the remaining economic life of distribution assets than transmission assets as they could significantly affect distribution assets in particular locations serving particular markets. For transmission assets gas volumes carried may decrease but are unlikely to decrease to uneconomic levels.

3.4 Institutional factors

The main institutional factors likely to impact Australia's gas industry over the next 10 years are competition, energy and environmental (particularly greenhouse) policies. Competition and energy policies are discussed in Section 3.4.1 and greenhouse policies in Section 3.4.2.

3.4.1 Competition and energy policies

Competition policy in the gas area is mainly concentrating on upstream structure, pipeline access and full retail contestability.

Upstream structure is of particular concern in eastern Australia as onshore fields are dominated by Santos and its partners, while offshore Esso-BHPP dominate. This lack of upstream competition is tending to favour higher ex-plant prices leading to lower demands for natural gas, particularly in the electricity generation market where lower gas unit capital costs often do not offset higher fuel costs. The issue is recognised by policy makers but ironically in a free market philosophy era governments appear reluctant to take action. Some upstream competition is emerging, particularly in the Otway Basin where Origin, Woodside and Essential Petroleum Resources (on-shore) are challenging BHP-Esso's dominance. In the Gippsland Basin, for example, the OMV/Energex consortium are challenging, albeit in a small way at this time, BHPP-Esso's dominance. And again in a small way coal seam methane producers/explorers are an emerging competitor.

Overall we judge that competition is increasing leading to some movement towards lower ex-plant prices and, *ceteris paribus*, higher gas demands. In the longer term as eastern Australian reserves are depleted, gas prices will depend on transmission tariffs and costs of, and competition in, WA/NT reserves development.

The pipeline access regime is also encouraging upstream competition.

Full retail contestability, although its effects are constrained by upstream concentration and low distribution and retail margins, is also tending to lower prices and increase demands.

3.4.2 Greenhouse policies

In the wake of the United States pull out from the Kyoto Protocol to reduce greenhouse gas emission growth over the 1990-2012 period, greenhouse policy trends are difficult to predict. Nevertheless the last international meeting on the Protocol (Conference of the Parties, COP6) did reach some agreement on outstanding issues and more progress seems likely at the COP7 meeting in Marrakech, Morocco, in November 2001. However, uncertainty prevails given recent world events.

We judge that even though Australia may not ratify the Kyoto Protocol and thus not formalise the commitment to reduce greenhouse gas emissions, Australia will continue to work towards the target of holding average 2008-12 emissions to 108 per cent of 1990 emissions.

Natural gas is the most greenhouse benign of fossil fuels having about 40 per cent lower emissions per unit of energy contained than coal (black coal energy can be more efficiently extracted than that of brown coal) and 20 per cent below petroleum products. With these characteristics the efficient use of gas is promoted in the National Greenhouse Strategy and State greenhouse strategies. For example cogeneration under the federal Greenhouse Gas Abatement Program (GGAP) and in Queensland's Clean Energy Policy (a target of 13 per cent of electricity consumption from gas generators by 2005).

On balance we judge that greenhouse policies will provide an additional stimulus to gas demands in eastern and elsewhere in Australia over the period to 2020.

This additional stimulus appears to be built more into NIEIR projections than ABARE projections.

3.4.3 Other factors

Factors such as **rezoning** and **forced pipeline relocations** could affect remaining economic life and result in some network loss. **Unexpected, unspecified (contingency) factors** such as unexpectedly stringent environmental policies affecting natural gas production and use might reduce the economic life of GasNet system elements. These factors could emerge at any time but are more likely to have an impact in distant periods (post 2020) where operating conditions are more difficult to predict at this time.

Thus a range of unforeseen, quite unexpected circumstances are likely to occur over a 40 year time span. For example, some market areas which seem to have a secure long term future could be abandoned through competitive pressures. Other major customers may come forward but are unlikely to be all in the same location as those that disappear. Or some emissions from natural gas using equipment could be deemed a health hazard and thereby force the loss of major markets through regulation and/or the high costs of removing the deemed health hazard emissions.

In estimating remaining economic life of long-lived assets should take account of such unspecified events occurring and affecting the life of network assets. Although difficult to estimate their probabilities of occurring it is very unlikely there is a zero probability that unforeseeable factors will not have an impact on asset lives in the very long (post-2020) term. Put another way, 30 years ago some factors affecting today's energy demands were not foreseen.

4. Estimates of the effects of factors on the remaining economic life of the GasNet network

4.1 Introduction

The effects of the above factors on each sector and the natural gas transmission system, are discussed and estimated below.

The analysis was conducted over three periods: 2001-2012, 2013-2025 and 2026-2040 for each system element, the Longford-Dandenong (A), the South-West pipeline (Geelong to Port Campbell) (B) and the other elements (C) of the GasNet system.

The selected periods are subject to differing degrees of uncertainty and the system analysis split is that the Longford-Dandenong section is more vulnerable to Gippsland Basin depletion, the South-West pipeline to Otway and Bass Basin reserves, and the rest of the system to overall eastern Australian reserves.

4.2 Technical life of system elements

As indicated above expected lives for transmission assets have been reviewed and remaining technical life re-estimated by GHD Ltd as follows:

Element A	28 years
Element B (total)	57 years
Element B (S/U)	59 years
Element B (R)	52 years
Element C	37 years

The GHD report has been included in the Appendix to this report. The increase in the weighted average life arises from the addition of new pipes to the network.

4.3 Remaining economic life of system elements – factor analysis

4.3.1 Introduction

For each asset element the remaining technical life is adjusted by economic factors to determine the remaining economic life (REL) of each asset element.

The results presented below for the remaining economic life (REL) of each system element are based on probability analysis. This methodology provides a means of handling the uncertainty of future events, for example depletion of gas reserves, for which predictions cannot be definitive, but for which some data and knowledge are available.

Estimated probabilities of events occurring that would reduce remaining economic life may be used to quantify the impact of these events on remaining economic life.

Probabilities range from 0 (event will not occur) to 1.0 (event will certainly occur). The probability values of events occurring are estimated as objectively as possible from available data and the judgment of knowledgeable persons. In this study this approach is used to estimate probabilities of events occurring that could impact on the remaining economic life of GPU GasNet's transmission network.

Application of this mode of analysis is given in the examples below.

1. It is estimated that there is an 0.5 probability, that is an even chance that the Gippsland Basin will be depleted by 2025 and that there is an 0.3 probability that element A will not be used for carriage of gas from other basins to markets along the route of element A. The probability of element use on resource depletion offsets the impact of reserves depletion on REL. The degree of offset depends on the probability of use or non-use. The higher the probability of non-use the greater the influence of reserves depletion on REL. Conversely the higher the probability of use the lower the influence of reserves depletion.

   The impact of these probability estimates in element A is given by:

   $$0.5 \times 0.3 = 0.15$$

   The interpretation of this result is that the remaining economic life (REL) of element A in 2025 will be 15 per cent below the remaining technical life (RTL) in 2025.

2. It might be estimated (hypothetical) that there is an 0.9 probability that demands for gas will cease due to environmental policies in 2040 and that there is a 0.9 probability that the network would not then be used for other purposes.

   The impact of this probability estimate on all elements would be:

   $$0.9 \times 0.9 = 0.81$$

   The interpretation of this result is that the REL of the network would be 81 per cent below RTL in 2040.

4.3.2 Element A – Longford to Melbourne

The remaining economic life of this element of the network is largely dependent on the Gippsland Basin which has relatively large reserves but which over the next 20 years will be drawn on by Victorian, New South Wales and Tasmanian markets.

Depletion of the basin depends on reserves and draws on those reserves. Depletion probabilities are estimated by considering official reserves and our estimate from NIEIR and ABARE projections of an average of 450 PJ per year draw on this basin's reserves for Victoria, New South Wales and Tasmanian markets over 2001-02 and 2019-20. On this basis remaining life of the reserves would be about 18 years but would be about 27 years if reserves turned out to be 12,000 PJ.

Thus on current reserve and demand estimates the Gippsland Basin is likely to be depleted before the technical life of the Longford-Dandenong pipeline is reached. The situation is uncertain because of:

(i) the difficulty of assessing the actual reserve situation in the Gippsland Basin; and

(ii) the range of demand and supply possibilities, particularly in an interstate connected pipeline system.

The above assessment of the situation indicates that Gippsland Basin reserves could be depleted between 2020 and 2030.

We estimate that:

(i) there is a 0 probability that Gippsland Basin reserves will be depleted by 2013;

(ii) a 0.5 probability that Gippsland Basin reserves will be depleted between 2013 and 2025; and

(iii) a 0.95 probability that Gippsland Basin reserves will be depleted between 2026 and 2040.

If Gippsland Basin reserves were the only consideration in estimating REL the REL would depend on depletion date estimates. We estimate, considering official reserve and actual reserve estimates and draws on the basin, that depletion date will be between 2019 (official reserves basis) and 2035 (actual reserves at 0.95 probability level).

However, the impact of Gippsland Basin reserves depletion on element A is to some extent offset by the possibility of the element being used for reverse flows from other basins. For example, to supply regional gas fired stations which are likely to have an installed capacity of over 600 MW by 2005. The viability of regional gas uses once the Gippsland Basin is depleted will depend on delivered gas prices and the resultant competitive position of these uses.

We do not believe that there is a zero probability that the line will not be used for reverse flows. The probability that it will not be used is judgmental, but we believe it to be reasonable. (The higher the probability it will not be used the greater the influence of reserves depletion on REL.)

The probabilities of the economic life of the pipeline element expiring in each period as a result of the above considerations are estimated as:

(i)	2001-2012	0;
(ii)	2013-2025	0.5 x 0.3 = 0.15 = 15 per cent reduction in remaining technical life; and
(iii)	2026-2040	0.95 x 0.3 = 0.29 = 29 per cent reduction in remaining technical life.

4.3.3 Element B – Port Campbell to Melbourne

This element of GasNet's transmission network will rely mainly on Otway Basin reserves to meet Western Victorian and Geelong regional markets and if reserves are found to be sufficient, part of the Melbourne region market.

At the moment estimates of reserves in these basins is particularly difficult because of the early stage of exploration and the recently announced discoveries at levels substantially above the official reserves.

Depletion of these reserves is uncertain because of the limited current capacity to transmit these reserves to market and the early stage of additional transmission capacity development.

Based on official recoverable reserves and expected draw on the reserves, the Otway and Bass Basins would be depleted by 2011, but not until after 2030 based on likely drawn on reserves and likely reserves given recently announced discoveries (Geographe and Thylacine).

We estimate that:

(i) there is a 0.05 probability that Otway and Bass Basin reserves will be depleted by 2013;

(ii) an 0.5 probability that these basins will be depleted between 2013 and 2025; and

(iii) an 0.95 probability that the basins will be depleted between 2026 and 2040.

Each probability is an average for the period. It must be emphasised that at this time actual reserves in the basins are very uncertain given the early stage of their exploration and developments. Accordingly these probabilities are contentious.

When the basins are depleted the regional markets are likely to be supplied from Western Australian/Northern Territory basins and most of the network would be used to transport this gas to the regions or to Melbourne. As the transmission system is connected to the Pt Campbell Underground Storage facility which performs the essential task of stabilising system flows and adding to their security there is a low probability that the main part of the network element will not be maintained.

However, some part of the system could be bypassed, particularly the Western Transmission pipeline from Pt Campbell to Portland (about 25 per cent of the element). This system part will probably be negatively impacted to some extent by the proposed SEAGas pipeline from Pt Campbell to Adelaide. This proposed pipeline, proposed to commence operation in 2004, now going through an environmental impact statement (EIS) process is a joint venture of Origin Energy and Australian National Power. The proposed pipeline parallels GasNet's Western system and could carry a majority of that pipeline's load, depending on the final design of, and demands on, the SEAGas pipeline. Thus the Western system part of Element C could be bypassed and become a stranded asset by 2005. Bypass possibilities, like reserve depletion considerations, decrease the REL of the system element.

The problem with treating element B homogenously is that the major part of the system, the South West (SW) portion, connects Melbourne with the Underground Storage (UGS) at Port Campbell. Given the system security importance of this SW/UGS system bypass of it is very unlikely.

Hence, the element B is treated at two sub-elements, element B (S/U) and B (rest):

(i) Element B (S/U). Element B (S/U) is treated as a sub-element where REL is reduced to some extent below RTL in recognition that over the long RTL of 59 years, demand and supply conditions and technological change could obviate the need for the UGS system.

Our estimate is these considerations would reduce the REL of element B (S/U) by about 10 per cent, that is to 6 years below the RTL of 59 years.

(ii) Element B (rest). Here reserve depletion probabilities (as above) are combined with bypass probabilities (that is bypass not like non-use reinforces the impact of reserves depletion on REL).

Probabilities

Reserves depletion

2001 – 2012	0.05
2013 – 2025	0.50
2026 – 2040	0.95

Bypass probabilities

- 2001 – 2012 = 0.3
- 2013 – 2025 = 0.4
- 2026 – 2040 = 0.5

Combining probabilities give RTL reductions in each period for element B (rest) of:

- 2001 – 2012 = 0.05 x 0.3 = 1.5 per cent
- 2013 – 2025 = 0.50 x 0.4 = 20 per cent
- 2026 – 2040 = 0.95 x 0.5 = 47.5 per cent.

4.3.4 Element C – rest of GasNet system

This system element covers a large and diverse area of north western, central and north eastern Victoria, mainly supplied at this time from the Gippsland Basin but also from the Cooper/Eromanga Basin. In the future the Otway and Bass Basins will also be used for supply to markets in this network element. As eastern Australian reserves are depleted we judge that most of the system would be supplied from Western Australian/Northern Territory basins and possibly CSM and the P-NG.

The element however, is likely to be affected by competing pipelines which may be developed in the future. For example, a new large capacity pipeline from the Moomba (South Australia) but and linked to the high reserves WA/NT basins could, via laterals or designed route, economically serve many load centres in northern and central Victoria. The probability of this occurring increases as south-eastern reserves move towards depletion.

GasNet system bypass possibilities are difficult to predict but they cannot be ignored. Bypass eventuality will depend on the economics of competing systems which will be mainly based on wellhead prices of sources and the tariffs required for each pipeline's viability. Higher volumes would give lower tariffs; wellhead prices depend on competition, exploration and development costs.

Taking the possibilities into account, the probabilities of the economic life of this network element expiring in each period are estimated as follows:

(i)	2001 – 2012	0.01 = 1 per cent;
(ii)	2013 – 2025	0.05 = 5 per cent; and
(iii)	2026 – 2040	0.15 = 15 per cent.

4.3.5 Impact of factors affecting all three system elements

As indicated in Section 3.4.4, factors such as rezoning, forced pipeline relocations and unexpected, unspecified (contingency) events could affect the remaining economic life of **all** (impact on each element is assumed to be similar) network elements. It is difficult to claim there is a zero probability that unforeseeable factors will not have an impact on asset lives, particularly in the post-2020 period.

The estimate of the impact of these factors on asset lives in each period are:

(i) 2001 – 2012 0 (negligible);

(ii) 2013 – 2025 0.02 = 2 per cent reduction in remaining technical lives; and

(iii) 2026 – 2040 0.05 = 5 per cent reduction in remaining technical lives.

4.4 Remaining economic life of system elements – results

Results of the study analysis of the remaining economic life of GasNet's transmission assets, based on RTL reductions, are presented in **Table 5**.

Remaining economic life (REL) of system elements is arrived at by applying the reduction in remaining technical life (RTL) estimated by the factor analysis in Section 4.3 to each network element in each analysis period. (Note that this analysis gives estimated average reductions of RTL in each period.)

The interpretation of the results for element A (Longford to Melbourne) is that the remaining economic life (REL) is 21 years, giving an REL expiry date of 2022 compared with an RTL date of 2029.[7]

For element B (SW/UGS) the REL is 51 years giving an expiry date of 2052 compared with an RTL date of 2060.

For element B (rest) the REL is 27 years giving an expiry date of 2028 compared with an RTL date of 2054.

For element C (rest of system) the REL is 30 years giving an expiry date of 2031 compared with an RTL date of 2040.

As emphasised throughout the report, all factors impinging on remaining economic life of system elements are difficult to quantify and therefore the results are not presented as being definitive.

The estimated reduction in remaining technical life from the factor analysis is adjusted (reduced) to take into account that factors may be coincident, that is may not be additive. For example, stringent environmental policies may coincide with the reserves depletion and impacts on a similar part of the network.

The estimate of REL in Table 5 is based on factor probability analysis being used to estimate the reduction of RTL of the network elements.

[7] Note that estimated REL for element A in the 2026-40 period is 19 years but is 24 years for the 2013-2025 period, indicating by this approach that REL is zero as the element enters the last period. Hence the 19 year estimate for the last period is only useful as a guide to the element's REL trends. The factor analysis thus indicates an REL of between 19 and 24 years; we have chosen 21 years and an expiry date of 2022.

Table 5 Estimates of remaining economic lives of system elements based on RTL reductions

Time period	2001 – 2012				2013 – 2025				2026 – 2040			
System element	A	B (S/U)	B (R)	C	A	B (S/U)	B (R)	C	A	B (S/U)	B (R)	C
Remaining technical life (RTL) years from 2001	**28**	**59**	**52**	**37**	**28**	**59**	**52**	**37**	**28**	**59**	**52**	**37**
Factor												
Reserves/demands (per cent reduction of RTL)	0	0	1.5	1	15	0	20	5	29	10[1]	47.5	15
Other factors (per cent reduction of RTL)	0	0	0	0	2	2	2	2	5	5	5	5
Total reduction of RTL	0	0	1.5	1	17	2	22	7	34	15	52.5	20
Adjustment for coincidence of factors	10% reduction	10% reduction	10% reduction	10% reduction	10% reduction	10% reduction	10% reduction	10% reduction	10% reduction	10% reduction	10% reduction	10% reduction
Adjusted reduction of RTL (per cent)	0	0	1.35	0.9	15.3	1.8	19.8	6.3	30.6	13.5	47.25	18.0
Estimated REL	28	0	51	37	24	58	42	35	19	51	27	30

Note: 1. Special factors effecting element B (S/U).

A **second** approach to estimation of REL could be based on estimates of eastern Australian reserves depletion at a 0.95 probability level, subject to any RTL constraint.

For element A (Longford to Melbourne) we estimate that this date (for Gippsland Basin reserves) would be around 2035 giving an REL of 28 years (RTL constraint) for the element.

For element B (S/U) operation on more remote reserves when eastern Australian reserves are depleted gives an REL which is similar to the RTL of 59 years.

For element B (R) given the significant uncertainty of Otway/Bass Basin reserves we estimate this date to be around 2040. On the other hand this element could operate on more remote reserves giving an REL similar to the RTL of 52 years.

For element C (rest of the system) reserve considerations indicate that most of the system C would continue to operate on more remote reserves when eastern Australian reserves were depleted. Under this approach for this element REL is similar to the RTL of 37 years.

This approach ignores the probabilities that reserves could be depleted earlier, other reserves could be used, back haul is uncertain, bypass is a possibility and that other factors could affect REL.

A **third** approach is to conclude that the analysis of factors in the report indicate that they will not have a significant impact on the REL of the elements given that total gas reserves (eastern-Australia, CSM, WA/NT and P-NG) available to Victorian markets will last until about 2060. In this situation the REL of each element would be only constrained by RTL.

This approach ignores the impacts of eastern-Australian reserves depletion and other factors such as bypass on the REL of system elements.

4.5 Conclusions

Each approach has some merit but we tend to favour the first, that is based on RTL reduction, but with recognition of the other approaches impacts on REL, resulting in recommended RELs as follows:

Element A	23 years – the economic life expiry date is 2024
Element B (S/U)	52 years – the economic life expiry date is 2054
Element B (R)	30 years – the economic life expiry date is 2031
Element C	32 years – the economic life expiry date is 2033

5. Summary and conclusions of economic life analysis

The remaining economic life (REL) of GasNet's transmission network assets is determined by a number of factors. These factors may be grouped as: technical life which sets the upper limit on REL, unexpected technical problems (not quantified in this study), gas reserves and demands on them, and institutional change. On the basis of current knowledge available to us, estimates were made of the quantitative impact of these factors in three periods: 2001-2012, 2013-2025 and 2026-2040, using a probabilistic approach and adjusting for the potential incidence of the factor impacts.

Each estimate was difficult to make and each factor is discussed in the report to give an appreciation of the difficulties. The results indicate that **over time the probability of reduction in economic life increases** because of reserves depletion in eastern Australia and increasing uncertainty about the institutional and general environment in which the transmission network would operate.

Several approaches to using the results were assessed.

The assessment results are presented below for elements A (Longford to Dandenong), B (South West System) and C (rest of the system).

These results indicate that on the basis of assumptions used in this study the remaining economic life of GasNet's transmission assets is lower than the technical life for each element.

Approach	Remaining economic life (REL), years				Expiry year of economic life			
	Element A	Element B (S/U)	Element B (R)	Element C	Element A	Element B (S/U)	Element B (R)	Element C
1. Factor analysis results applied to remaining technical life	21	51	27	30	2022	2052	2028	2031
2. Reserves constraint	28	59	52	37	2029	2060	2053	2038
3. No constraint of non-RTL factors studied on REL	28	59	52	37	2029	2060	2053	2038
Recommended REL	**23**	**52**	**30**	**32**	**2024**	**2053**	**2031**	**2033**

The recommended approach is a compromise which, after a review of all the factors and a consideration of various approaches to the factor analysis results, appears to be a reasonable judgment on the remaining economic life of the transmission assets.

The results are particularly sensitive to estimates of reserves depletion (particularly in the Gippsland Basin) and to estimates of asset utilisation as new pipelines are built, eastern Australian gas reserves deplete and as remote gas reserves are introduced to eastern Australian markets.

6. Regulatory and legal factors and trends impacting on the commercial life of GasNet's transmission assets

6.1 Introduction and overview

This section of the report to GasNet covers regulatory and legal factors affecting the commercial life of the transmission assets owned by GasNet.

The concept of depreciation is first discussed and a definition of depreciation is offered from a theoretical point of view. Reasons for the diminution in the value of Capital Assets are briefly discussed.

The statutory aspects of taxation depreciation under the current regime provided by the Income Tax Assessment Act is summarised with particular emphasis given to recent developments regarding the assessment and re-assessment of the effective life of depreciable assets.

The theoretical and legislative base having been laid, there follows an analysis of depreciation of the assets of GPU GasNet (now GasNet) from the date of purchase on 2 June 1999.

Reference is made to the annual reports and financial statements of GPU GasNet and the depreciation methodology adopted by the company for its accounting purposes.

A comparison is made between the depreciation profile so adopted with that adopted by Transmission Pipelines (Australia) Assets Pty. Ltd. revealing a schedule that significantly accelerates depreciation of the same assets.

A detailed assessment of the valuation of the transmission pipeline assets is undertaken by reference to the valuation methodology adopted and the resultant value of assets for the purposes of the Access Arrangement for the Principal Transmission System and the Western Transmission System.

Particular note is made of the contribution of the Saturn Report to the assessment of remaining economic lives in the valuation of the assets for the Initial Capital Base under the Access Arrangement.

Then follows a discussion of the alternative perspectives for depreciation for accounting purposes, for taxation purposes and for regulatory purposes. The contrasting depreciation profile in each of the alternative perspectives is discussed and contrasted.

Possible reasons for a taxpayer adopting a lower depreciation profile for accounting purposes that has adopted for taxation purposes are briefly noted.

A brief overview of the Victorian gas transmission regulatory regime follows with a detailed discussion of the regulated asset base, its valuation, historical issues in relation to it and assumptions about the DORC valuation methodology is provided.

The calculation of the economic lives of the assets and the role of the Saturn Report in the determination of the remaining lives and the acceptance of those calculations by the ACCC in its decision on the Access Arrangement are covered.

Considerations by the ACCC in respect of the Capital Bases, depreciation, profiles and asset life estimates of other Access Arrangements under the National Code are discussed. Decisions for the Central West Pipeline and the Moomba to Sydney Pipeline in New South Wales, the Moomba to Adelaide Pipeline System and the Riverland Pipeline in South Australia, the Amadeus Basis to Darwin Pipeline in the Northern Territory, as well as decisions by the independent Gas Pipelines Act Regulator (OFFGAR) in Western Australia are analysed.

Some decisions of the ACCC as Regulator under the National Electricity Code and the Draft Regulatory Principle are examined to identify relevant principles and practices to shed light on the current disposition of the ACCC as Regulator of the relevant infrastructure transmission assets.

The asset valuation principles, the building of block approach for return of capital and the valuation of the transmission assets forming the capital bases of electricity assets are summarised.

Relevant decisions of the ACCC in the electricity jurisdiction include the New South Wales and Australian Capital Territory transmission network revenue caps, the Queensland transmission network revenue cap and the Snowy Mountains Hydro-Electric Authority Decision. In the latter case, a more detailed analysis of the approach to the valuation of the assets, in particular, estimation of the economic lives of the transmission power lines is provided.

Finally, the provisions of the Code regarding review of Access Arrangements are analysed and the bases under the Code for determination of the Capital Base on commencement of the forthcoming Access Arrangement period are particularly studied.

Consideration is given to the tension between a mechanistic approach to determining the Capital Base for the renewed regulatory period and other provisions of the Code that require maximal adjustment to the Depreciation Schedule for relevant assets for changes in the economic life of these assets. The requirement under the Code to allow for general risk to the service provider in providing the regulated service can influence the depreciation profile with consequential adjustment to revenue. The ACCC has demonstrated that it can choose to accelerate depreciation rather than reduce economic lives of assets.

6.2 Introduction to depreciation

A tax system based on income does not, in general, allow the taxpayer to make a deduction for the cost of an asset in the year in which that asset is purchased. The deduction is spread out over a period of time, consistent with the estimation of the useful economic life of the asset. That annual deduction generally approximates the reduction in the value of the Capital Asset as it ages and is called depreciation.

In the Draft Regulatory Principles, the ACCC has stated its preference for an economic definition of depreciation in the scheme for regulatory depreciation. The ACCC considered that this approach overcame shortcomings associated with traditional depreciation profiles based on accounting convenience rather than economic motivation. The ACCC identified the key problems with a regulatory framework using linear depreciation, nominal or real, as being the jump in tariffs and revenues as one major item of capital resource at the end of its useful life, is replaced by another and different age profiles of similar equipment used by service providers under the same regulatory framework. The ACCC was concerned to overcome inter-temporal and geographic economic distortions.

6.3 A definition of depreciation

Economic income is a measure of the change in a taxpayer's real economic well-being occurring over a specific time period, typically a period of one year for income tax purposes. Economic income reflects the taxpayer's consumption plus changes in wealth. Changes, up or down, in the value of Capital Assets, including plant and equipment, are part of the taxpayer's overall changing wealth and are included in economic income. Tax based on economic income must allow a deduction when assets fall in value; otherwise taxable income will be overstated.

The total change in an asset value over a period can be divided into two components. The first component is economic depreciation. This is generally defined as the decline in value of an asset as it ages. The difference in price between a two-year old motor car and a three-year old motor car is due to economic depreciation.

The second component is the aggregation of other factors affecting changes in asset value and can be described as the revaluation effect. Revaluation can include the result of changes in the relative price of an asset due to technological improvement in new assets relative to old assets, namely, obsolescence. The total change in the value of an asset over the period is the sum of economic depreciation, revaluation and if asset price change is nominal, as opposed to real, the effect of inflation can also be added.

Capital Assets, such as transmission pipeline assets, are durable and have value far beyond the fiscal year of the purchase or installation. The purchase or installation of Capital Assets in such a pipeline has no effect on economic income because one asset, money, is exchanged for an asset of equal worth, the pipeline. Accordingly, it is not the initial acquisition or installation cost but the change in the value of the asset over time that affects economic income. The decline in value, due to the durability of the asset, will continue for many years. The depreciation of that asset is an important component in the change in the asset's value over time.

6.4 Reasons for depreciation of capital assets

There are a number of reasons why Capital Assets depreciate, or fall in value through aging over their useful economic life. The value of an asset is the present discounted value of the net cash flow it can produce and therefore older assets have fewer years in their remaining asset life in which to produce income and are therefore of less worth than similar newer assets of the same type that can produce income flows over a longer life span. Further, Capital Assets can wear as they age and this can affect productivity or require more maintenance than newer assets of the same type. Technological improvements in similar new assets can also reduce the value of older assets on account of their obsolescence.

6.5 Statutory aspects of taxation depreciation

6.5.1 The statutory basis for depreciation

It is fundamental to recognise the statutory nature of depreciation for taxation purposes. Under the Income Tax Assessment Act, depreciation is a specific deduction, and is not an expense in the nature of a loss or outgoing. It is not deductible as a general expense. The basis upon which a taxpayer can rely for deduction for depreciation is that specifically set forth in the relevant provisions of the Income Tax Assessment Act. The relevant provisions of the Act refer to the deduction of an amount for depreciation for "plant". This is a defined term.

6.5.2 Plant

"Plant", also include references to "a unit of plant". They can be deducted for depreciation and is calculated **on the cost of the plant to the taxpayer**. For GPU GasNet, the base for depreciation for income tax is the price paid for the assets on purchase, not the valuation of the asset base for regulatory purposes.

The rate used to calculate the deduction for depreciation is generally based on the effective life of the relevant plant. There is a choice in the method of calculation; either the diminishing value method or the prime cost method. The legislation requires that the choice of method must be made in the income year in which a depreciation deduction is first claimed for the relevant plant.

Of the three factors mentioned above, the effective life is the central factor as the cost base for the asset is not usually in issue nor is the adoption or the meaning or definition of the alternative methods of calculation.

6.5.3 Effective life

The Act provides two methods for determining effective life. These are:

1. own assessment of effective life; or

2. the effective life specified by the Commissioner of Taxation.

The statutory right to either self assess effective life or to adopt the effective life calculation of the Commissioner first came into operation relatively recently. Until 30 June 1991, the Commissioner alone determined the effective life of plant for depreciation purposes.

The Act provides a mechanism to work out effective life. This involves estimating how long the relevant plant can be used by any entity for income producing purposes. Assessment must be made at the time the taxpayer first uses the plant or the time in which it is first installed ready for use for the purpose of producing assessable income. The Act requires certain assumptions:

- there will be wear and tear at a rate that is reasonable to expect having regard to the expected circumstances of use; and

- the plant will be maintained in reasonably good order and condition.

It is important to note that the above general assessment requirements do not restrict the taxpayer to confining its considerations to its own particular operations and circumstances. Rather, the requirement is that the taxpayer must enter upon a broad and general consideration in relation to the income producing purposes of "any entity".

6.5.4 Reassessment of effective life

A taxpayer may now vary its estimate of the effective life of plant. For assets acquired after 11.45 AM EST on 21 September 1999, the Act has permitted a taxpayer to either self assess or to adopt the Commissioners published schedule of effective lives.

The bases upon which a taxpayer can reassess effective life are problematic. It is unclear if the taxpayer can reassess on one occasion only or if there is an ongoing or multiple right to reassess. The Commissioner contemplates that unpredictable obsolescence leading to the scrapping of plant is one circumstance that will justify a review of effective life. It is problematic for both the Commissioner and to the taxpayer as to how events that lead to obsolescence can be predicted.

A non-exhaustive list of changed circumstances is set out in the Act and includes categories of consequence in the nature of increased or decreased wear and tear, economic obsolescence, regulatory obsolescence and technological obsolescence. On a reassessment, as on an original effective life estimate, the taxpayer must make a general estimate of the remaining effective life of the plant as used by any entity for income producing purposes. This seems to require the taxpayer to decide for the entire industry in which it operates. The requirement appears to be at odds with the driver for the reassessment which may include changes in circumstances particular to the taxpayer and which may not apply equally, or at all, to other industry members.

After the publication of the Ralph Report, the Commissioner undertook to update and expand the effective life schedule attached to taxation ruling IT 2685 to ensure that becomes as representative as possible.

The Commissioner issued draft ruling TR2000D/7 which included a review of individual assets and groups of assets used in various sectors including the power and gas industries with resultant changes to the estimates of effective lives. In that draft ruling, the Commissioner indicated that his determination of effective lives involves a consideration of listed factors which themselves were not intended to be exhaustive. He said that the weight given to each factor would vary depending on the nature of the asset and in considering the relevant factors the Commissioner could take into account only the normal industry practice. The Commissioner seems to take the position that he can only have regard to normal industry practices when estimating the rate of wear and tear for an item of plant. Taxpayers who decide to self assess are, it seems, able to factor their individual circumstances of use into the assessment. Invariably the taxpayer will choose to do so if it does not agree with the norm adopted by the Commissioner, and also as in the case where the taxpayer's use does not conform to an accepted industry norm.

6.5.5 Summary

The critical term "effective life" is not defined. The rulings enumerate, but do not exhaustively prescribe, the factors that are to be taken into account in the estimation of the effective life of plant. The taxpayer can adopt the effective lives for assets in the Effective Life Table to the tax legislation or he can self assess. making his own estimate taking into account the statutory assumptions. In turn, these assumptions require a further subjective decision by the taxpayer about their relevance to effective life having regard to the reasonableness of the rate of wear and tear in a taxpayer's expected circumstances.

Ultimately, the estimate of effective life of plant for depreciation is a question of fact to be decided on a case by case basis, taking into account the requirements of the legislation. For taxation purposes, the Capital Base is always considered in historical cost terms rather than in current cost terms. Accordingly, depreciation is calculated on the basis of historic cost.

The effect of reassessing the remaining effective life of an asset is to accelerate the depreciation deduction for that asset over the abbreviated remaining economic life of the asset. The taxpayer is not permitted, on a reassessment of effective life or otherwise, to also change the method of calculation of the deduction for depreciation and thereby to alternate between straight-line or reducing balance calculations.

6.6 GHD valuation

GHD was engaged by Transmission Pipelines Australia to value the assets in the transmission system on the basis of the DORC methodology as at 30 June 1997. Accountants Ernst & Young were engaged by TPA to provide interpretation and clarification of the commercial practices adopted in the DORC valuation methodology. The scope of the report on these commercial practices included considerations of the following:

(1) whether the ODRC methodology valuation of TPA's Transmission System assets was consistent with the Victorian Government's objectives for establishing tariffs including:

    (A) taking account of commercial market pressures;

    (B) reflecting the underlying economies of the pipelines;

    (C) facilitating competition; and

    (D) providing appropriate signals to customers and potential developers;

(2) the identification of any assumptions or changes in the valuation approach required to reflect the Victorian Government's objectives; and

(3) the identification of different judgments on asset valuation that could be taken to reflect the terms of reference for the valuation as at 30 June 1997.

This area of advice is central to the valuation of assets under the Code and the National Code. This DORC method is also used by the ACCC in setting price caps for electricity markets under the NEC.

Both the National Code and Code provide that the Capital Base of the subject network should normally fall somewhere between and DORC valuation and an historical cost valuation. The Codes provide flexibility and discretion for the relevant Regulator in the choice of methodology. The Codes provide discretion as to the adoption of asset valuation methodologies by a formal consideration of a number of factors including the advantages and disadvantages of each valuation methodology to the asset base. Despite the flexibility inherent in the Code, the ACCC has consistently adopted a DORC methodology, both as the Regulator in determining the price caps for electricity networks in the National Electricity Market, and in respect of gas Access Arrangements

TPA network assets were valued on an average Replacement Cost (RC) and on an average standard economic life basis. The ages of some assets were assessed on an average basis. The economic lives were based on industry experience, pipeline research, standard maintenance practice and specific research undertaken by Saturn Corporate Resources Pty. Ltd. Remaining lives of all assets were calculated as the overall economic life less the estimated age of the asset. Minimum remaining lives are assumed for each asset type – i.e., a minimum value is attributed to the asset if it is still providing gas transmission service after it has reached the end of its economic life.

The following table from the Access Arrangement Information lists the assessment by GHD of economic lives for the assets in the PTS and the WTS.

Table 2.2(c)(4)		
Pipeline Systems	Economic Life (Years)	Minimum Remaining Life (Years)
Principal Transmission System		
Transmission Pipelines	38-60	5
City Gate Regulating Stations	38-60	5
Field Regulating Stations	39-60	5
Compressor Stations	30	5
Odourisation Stations	35	5
Transmission Pressure Services	45	5
Western Transmission System		
Transmission Pipelines	37-47	5
Odourisation Stations	35	5

6.7 Summary of valuation

The DORC valuation by Treasury resulted in the value of assets at $347 million.

On 13 March 1998 supplementary information was provided by Transmission Pipelines Australia Pty. Ltd. concerning the proposed Access Arrangement submitted by Treasury. Amongst other information provided was a statement of the unaudited historical costs of transmission network assets.

The information was submitted subject to the caveats that the data had been sourced from the records of Gas Transmission Corporation and its predecessor, the Gas and Fuel Corporation, the data had not been subject to audit and EPD, and the Department of Treasury had been alerted and had advised the ACCC regarding significant inadequacies in the data. Nevertheless, it was said that the data provided was the best data available and should be treated with caution so far as drawing any conclusions from it.

The full historical cost of the network assets were estimated as follows:

Principal system	$259,509,000
Western system	$28,323,000
Total transmission historical cost	**$287,832,000**

A further additional document was filed on 16 March 1998 supplementing the information in the original Access Arrangement application. Included in that information was further information regarding depreciation so far as it impacted upon capital costs.

Concerning opening asset balances in Sections 2.2 and 2.3 of the Access Arrangement Information, it was pointed out that GHD also determined the economic lives of each asset type when conducting its valuation of system assets.

Additionally, a definition of economic life was provided:

> "Economic life is the period over which it is reasonably expected that income may be earned from an asset. On occasion this may be less than the technical life. Economic life rather than technical life is used in the calculation in order to allow for the full recovery of the asset value over its period of actual use."

Asset groupings by remaining economic life appear in the Table 2.2(d)(4) of the Access Arrangement Information document.

Table 2.2(d)(4)	
Remaining Life	CCA Asset Value $m[1]
Land	7.3
5 Years	2.7
5-20 Years[2]	22.0
33 Years	140.5
36 Years	191.7
	364.2

For depreciation calculations, assets were grouped by average remaining economic lives and by asset class. The aggregation of the assets and the weighted average remaining economic lives are shown in the above table.

Depreciation deductions (indexed) over the regulatory period were calculated using the above asset groupings and the remaining lives shown in Table 2.2(d)(4) as follows.

1998	$12.62 million
1999	$13.40 million
2000	$14.39 million
2001	$15.40 million
2002	$15.62 million

6.8 Victorian Gas Transmission regulatory regime – an overview

6.8.1 Legislation

Relevant legislation regulating the Victorian gas transmission industry comprises:

- the Gas Industry Act 1994 (as amended); and
- the Victorian Access Code ("the Code").

The Code was introduced by the Victorian Government ahead of the National Third Party Access Code for Natural Gas Pipeline Systems (the "National Code"). The National Code substantially mirrors the Code and will supercede it.

6.8.2 The Access Arrangement

The Energy Projects Division of the Victorian Department of Treasury and Finance (EPD) formulated the initial Access Arrangement for Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd for the Principal Transmission System (PTS) and the Western Transmission System (WTS). The final decision for that Access Arrangement was given by the ACCC on 6 October 1998 and the final approval was given on 15 December 1998.

The Access Arrangement is in force until 31 December 2002. The subsequent regulatory period is a period of five years commencing 1 January 2003.

6.8.3 The Transmission System Operator

GasNet is now the gas transmission system operator. It owns and maintains the transmission assets and provides gas transmission services. GPU GasNet acquired the PTS and WTS from Transmission Pipelines Australia and Transmission Pipelines Australia (Assets) on 2 June 1999. Pursuant to section 9.3 of the Code, the purchaser of a Covered Pipeline, becomes subject to any Access Arrangement approved under the Code.

6.8.4 Revised Access Arrangement

Subsequently, GPU GasNet sought approvals to revise the Access Arrangement to incorporate the Interconnect assets and the South West Pipeline. The ACCC gave its Final Decision approving the revisions for the Interconnect assets on 28 April 2000 and its Draft Decision in respect of the South West Pipeline on 11 May 2001.

6.8.5 Review of Access Arrangements

The Code provides that an Access Arrangement must include a date when the next revision to the Access Arrangement will commence (Revisions Commencement Date) and a date on which the Service Provider must submit proposed revisions (Revisions Submission Date).

The Revisions Submission Date under the Access Arrangement is 30 March 2002 by which date the Service Provider must submit proposed revisions to the Access Arrangement accompanied by the necessary Access Arrangement Information. The proposed revisions must, at the least, include the elements described in sections 3.1 through 3.22.of the Code.

6.9 Background to the Regulated Asset Base

6.9.1 Initial Capital Base

It is well understood that the initial Capital Base has a sustained effect upon the level of tariffs over a lengthy period due to the long life of transmission pipeline assets.

Section 8.10 of the Code prescribes the factors to be used in determining the Capital Base for existing pipelines. The factors described in sections (a) through (k) are factors that “should be considered in establishing the initial Capital Base.” Section 8.11 states that the Capital Base so determined “should not fall outside the range of values determined under these factors in paragraphs (a) and (b) of Section 8.10.”

The initial Capital Base for the Principal Transmission System and the Western Transmission System is determined by the ACCC Access Arrangement Decisions made in 1998 on the application of Energy Projects Department of Victorian Treasury ("EPD"). The network assets were then owned by Transmission Pipelines Australia Pty. Ltd. (TPA) and Tasmanian Pipeline Australia (Assets) Pty. Ltd. (TPAA).

Section 8 of the Code also sets out the principles with which Reference Tariffs and a Reference Tariff Policy included in an Access Arrangement must comply. The Reference Tariff Principles specify three alternate methodologies for determining the Total Revenue. Of these, the Cost of Service methodology was adopted in the Access Arrangements. In turn, that methodology requires Total Revenue to be set to recover costs calculated on the basis of a return on the value of the assets that form the Capital Base, depreciation on the Capital Base and operating, maintenance and other non-Capital costs incurred in delivering the relevant services.

Relevant to this advice are the issues concerning Depreciation and Depreciation Schedule. The explanatory introduction to Section 8 of the Code sets forth a number of broad principles for establishing the Capital Base and there are also a number of principles specified for the Depreciation Schedule. One important such principle is that:

> "depreciation should be over the economic life of the assets that form the Covered Pipelines …"

The term "economic life" is not a defined term under the Code.

6.9.2 Valuation of the Regulated Asset Base

Specialist valuer Gutteridge, Haskins & Davey Pty. Limited (GHD) was employed to determine the valuation of the transmission system assets. This valuation was carried out on the basis of the Depreciated Optimised Replacement Cost methodology (DORC). It is unnecessary here to describe DORC methodology or the circumstances in which it was selected as the basis to value the relevant assets.

In its considerations of the proposal by EPD concerning the DORC valuation, the Commission noted that the methodological flexibility allowed in the Code may:

> "reflect the recognition in the Victorian Access Code that for an existing pipeline being brought into an access regime, there is no economically "right" valuation for the purpose of tariff determination and market-determined approaches will involve a circular analysis." (page 31, Final Decision, 6 October 1998).

At page 32 of the Final Decision, in discussing valuation methodology and economic theory, the ACCC noted that its discussion assumed that the treatment of existing assets can be separated from the treatment of new assets. It said:

> "While the Victorian Access Code clearly separates the treatment of existing assets from new assets, industry participants are likely to see the regulator's treatment of existing assets as setting a precedent for how it will exercise its [generally wide] discretion when making other decisions under the Victorian Access Code in the future. Therefore, opportunistic behaviour by the Regulator with respect to existing assets may dampen the incentives to investment in the industry."

The ACCC has administered a self-imposed caution against opportunistic behaviour on its part as the Regulator of tariffs under the Code. By inference, it has also diluted industry concerns that its decision on the initial Capital Base must be regarded as a precedent. The issue here is that the initial Capital Base determined under the Access Arrangements in 1998 will be the starting point from which the opening Capital Base of the next regulatory period will be calculated.

6.9.3 Historical Issues and Initial Capital Base valuation under the Code

There were concerns about "informational shortcomings" when considering the historical valuation of the transmission service assets in the Access Arrangements. The transmission services were separated from the distribution services in December 1994 by Gas Transmission Corporation. Subsequently, TPA was formed. There were multiple changes in classifications of assets over the period from 1957-1958. These difficulties were considered in the context of the attempt to evaluate the basis from which tariffs appear to have been set in the past and to identify historical returns.

Dealing with the future, rather than the past, the ACCC observed that the Code requires a broader perspective to be taken when determining the value of existing assets to determine a reasonable balance of interests between the Service Provider and Users and Prospective Users as required under Sections 2.24(b)(i) and (vi) of the Code. The ACCC also considered, pursuant to Section 8(10) the relevance of factors such as the price paid for assets recently purchased by the Service Provider and the circumstances of purchase, as well as the reasonable expectations of persons under the regulatory regime that applied prior to the commencement of the Code.

The ACCC expressly concluded that it was not required to adopt the sale price of assets sold prior to the introduction of the Code as the regulated asset base. The transfer of the transmission pipeline assets from the Gas and Fuel Corporation of Victoria to TPA (if it was a sale in ordinary meaning of that term) would not be considered as an arm's length sale and would, in any event be discounted in considering these factors. The ACCC preferred to consider government ownership of TPA and privatisation as matters relevant to be considered under clause 8.10(k), "other factors considered relevant by the Regulator", rather than as circumstances surrounding the transfer of the assets to TPA. Having done so, the ACCC then excluded these matters as relevant "other factors" on the basis that the Code made no distinction between government and privately-owned pipeline systems.

6.9.4 Valuation Assumptions Concerning the DORC Valuation

Sinclair Knight Merz Pty. Ltd. (SKM) was retained to "desk check" the GHD valuation – a DORC valuation calculated as at 30 June 1997. That valuation expressly took into account factors including technological change, transgeographical shifts and demand and then current estimates of proven and probable gas reserves in Australia. In making that valuation, various assumptions were made. Relevantly, those assumptions include:

1. adopting an average standard economic life; and

2. assessing the ages of some assets on an average basis.

In turn, GHD estimated remaining economic life for all assets as the economic life less the estimated age of the assets.

6.9.5 Calculation of Economic Life

TPA relied upon the expertise of GHD in determining replacement costs and economic lives, as well as in the provision of specific engineering judgments in the valuation of the transmission assets. Estimates of economic lives were based upon consideration of industry experience, pipe life research, standard maintenance practice and, significantly, specific research undertaken by Saturn Corporate Resources Pty. Ltd. (Saturn Report).

The Saturn Report considered the extent to which these factors affected the remaining economic lives of assets in the transmission system and divided the system assets into two components, one having an economic life up to the year 2030 and the remainder having an economic life up to the year 2033. A nominal minimal remaining life of 5 years was given to each asset type that may reach the end of its standard life but still provided a gas transmission service. The economic lives of the relevant assets are set out in Table 2.2(c)(4) of the Access Arrangement Information.

Table 2.2(c)(4)

Pipeline Systems	Economic Life (Years)	Minimum Remaining Life (Years)
Principal Transmission System		
Transmission Pipelines	38-60	5
City Gate Regulating Stations	38-60	5
Field Regulating Stations	39-60	5
Compressor Stations	30	5
Odourisation Stations	35	5
Transmission Pressure Services	45	5
Western Transmission System		
Transmission Pipelines	37-47	5
Odourisation Stations	35	5

The remaining lives for all assets were, as stated above, calculated as the economic life less the estimated age of the asset. The remaining lives assumed for the assets appear in Table 2.2(d)(4) of the Access Arrangement Information.

Table 2.2(d)(4)

Remaining Life	CCA Asset Value $m(1)
Land	7.3
5 Years	2.7
5-20 Years(2)	22.0
33 Years	140.5
36 Years	191.7
	364.2

It appears clear from extrapolating these tables that the ACCC accepted the determination of remaining economic lives in the Saturn Report. No asset is given a remaining life of more than 36 years as at the valuation date, 31 December 1997, a period expiring in 2033. Similarly, those assets with a remaining life of 33 years would expire in 2030. These are the dates for the several components of the transmission system assets determined in the Saturn Report.

In its Final Decision, the ACCC considered that a fair value for the initial asset base of the transmission system was $363M.

6.9.6 Summary

It seems clear that the valuation of GHD, the review of the assumptions and other Code fundamentals by Ernst & Young and the considerations of the ACCC, all adopted the remaining economic lives as assessed in the Saturn Report. By necessary implication, the considerations and methodology that produced those estimates in the Saturn Report are also adopted.

6.10 Revision of Access Arrangements by GPU GasNet Pty Ltd

GPU GasNet applied for two revisions.

6.10.1 The Interconnect

On 26 August 1999, GPU GasNet applied for a revision to the arrangement to expand the Capital Base of the Principal Transmission System. The basis for the application to amend the referenced tariffs in respect of the Interconnect assets was that the addition of those assets passed the Code's system-wide benefits test. This basis was ultimately accepted by the ACCC. The total estimated capital costs of the assets proposed to be included in the Capital Base was $40.4M.

GPU GasNet proposed three alternative methods for calculation of the revised tariffs, being:

- Option 1 – recovery of capital costs in one year (the year 2000);
- Option 2 – recovery of recovered capital costs over the balance of the first regulatory period ending 2002; and
- Option 3 – recovery of capital costs over the full economic life of the assets.

6.10.2 The ACCC chose Option 3. GPU GasNet stated a preference for either Option 1 or Option 2.

Specifically, at page 36 of the Draft Decision, the ACCC said:

> "The Commission proposes to accept Option 3 whereby, consistent with assets currently included in the PTS regulatory asset base (as approved by the Commission), the cost of the capital for Interconnect assets would be recovered over their useful lives. The economic life of the Interconnect Pipeline has been assumed to extend to 2033 (consistent with the life other PTS pipeline assets), whereas the economic life of the Springhurst Compressor has been assumed to extend to 2028 (consistent with the 30-year technical life)."

The ACCC adopted, without comment, the remaining asset lives in the Saturn Report. It is worthy of note that, in passing under "Other issues", the ACCC considered the requirement that provisions in an Access Arrangement can only be approved by the ACCC if in full compliance with the Code. In particular, a proposed revision must contain the elements and satisfy the principles in section 3.1 through 3.20 of the Code. The ACCC considered whether any of the elements of the Access Arrangement, as revised by the proposed revision, would be inconsistent with those requirements of the Codes. This consideration centred on the impact of the proposed revisions and did not extend to a full review of the Access Arrangements themselves. Nor did the ACCC contemplate anticipating the review to be conducted during 2002.

Accordingly, the ACCC stated at page 39 of the Draft Decision:

> "The review therefore focuses on the impact of the proposed revisions on whether circumstances have changed since 1998, such that the Access Arrangement would no longer contain the elements and satisfy the principles set out in sections 3.1 to 3.20 of the Code."

The Commission identified one particular area, namely, significant changes in the market for funds in relation to the appropriate Rate of Return pursuant to section 8.30 of the Code.

The significance of the above is that the ACCC, as Regulator, must expressly consider overall Code compliance in the context of a revision application. In particular, the ACCC considered changes in a dynamic factor (the market for funds) applying since the commencement of the Access Arrangement. This is the factor specificied in section 8.30 along with a general category of factors described as "the risk involved in delivering the Reference Service".

Any factors affecting the remaining economic lives of the substantial capital assets that have arisen since the determination of the initial Capital Base should also be considered as risks falling within the general risk category and taken into account in considering the appropriate Rate of Return on reset of Access Arrangements in 2002.

6.10.3 The Southwest Pipeline

On 12 September 2000, GPU GasNet applied for approval of a revision to the Access Arrangement for the Southwest Pipeline.

The Southwest Pipeline was constructed following the Longford fire and explosion in September 1998. The works were constructed and commissioned under an accelerated timetable to enhance available gas supplies on the PTS by the winter of 1999. The total proposed roll-in costs of these assets was $75.5M.

GPU GasNet proposed recovery of capital costs of the Southwest Pipeline through an increase in the Longford injection charge and the introduction of a new Port Campbell injection charge set at the same level. Following an extensive process of public consultation, the ACCC decided against introducing any major change to the balance of charges faced by users. Instead, it deferred detailed scrutiny of the issue until the review of the Access Arrangement in 2002. The ACCC ruled that the proposed reference tariff structure was inconsistent with the principles set out in section 8 of the Code.

Regarding depreciation, GPU GasNet proposed real straight-line depreciation to the actual costs of the pipeline assets from the date of commissioning on 1 June 1999 to the proposed implementation date for the revised tariff, 1 October 2000, as well as deferral of $8.2M of depreciation for the years 2000-2002, with the target revenue being levelised during the subsequent 20 years.

In its Final Decision, the ACCC said at page 64:

> "The Commission considers it appropriate that changing usage over time be reflected for regulatory purposes in the depreciation schedule. It has concluded that GPU GasNet's proposal to back-end depreciation from October 2000 is not unreasonable."

This comment acknowledges the requirement of section 8.33(c) of the Code to adjust depreciation for changing usage over time.

The ACCC did not approve real straight-line depreciation of the pipeline prior to October 2000 because it concluded the methodology may not be consistent with the amount of revenue earned prior to that date.

In respect of the substantial depreciation back-ended to 2020, the ACCC's decision demonstrates an acceptance that, for regulatory purposes, the depreciation schedule used in tariff setting must be flexible in reflecting changing usage over time. Put another way, the depreciation profile, when assessed at a particular point in time, should reflect the usage of assets over their future economic life.

6.11 Access Arrangements in other States

The ACCC has approved Access Arrangements for transmission tariffs in Victoria, New South Wales, South Australia and the Northern Territory but not, as yet, in Queensland or in Western Australia.

The approach taken by the ACCC on asset lives and depreciation in these decisions points current principles and practices adopted by the ACCC as Regulator under the gas codes. Consideration of the relevant practices and principles for relevant issues in the decisions of OffGAR, the jurisdictional Regulator of gas transmission services in Western Australia, is also useful as a reference check because its decisions are also made under the provisions of the National Code.

6.11.1 New South Wales Decisions

Central West Pipeline

On 31 December 1998, AGL Pipeline (NSW) Pty. Ltd. submitted an Access Arrangement for approval under the National Code for the Central West Pipeline between Marsden and Dubbo in New South Wales. This pipeline is part of the New South Wales gas distribution network of AGL and provides the link to the Moomba to Sydney pipeline. The Central West Pipeline became operational in 1998.

Capital Base

The initial capital Base was determined by AGL on the basis of the actual cost of construction, after some optimisation for oversizing and adjustment for a government grant. The proposed valuation was $24.8M as at 30 June 1999.

The ACCC accepted this valuation methodology as consistent with the regulatory framework as it allowed for revenue uncertainty in the early years of a new pipeline without significant base contracts.

Depreciation

AGP proposed economic depreciation of the pipeline assets. This allowed for under-recovery in the early years of operation to be offset by over-recovery in later years. Specifically, this methodology proposed recovery of costs over the efficient life of the asset in accordance with section 8.1(a) of the Code. The ACCC concluded, subject to reservations, that the proposed use of economic depreciation was a means to level out initial under-recovery of costs and was consistent with the principles of the Code.

Asset Life Estimate

AGL stated that the cumulative effect of recent Access Arrangements, its own industry experience, the experience of other industry participants and decisions of Jurisdictional Regulators, have established the economic lives for various assets making up the pipeline.

AGL made a distinction between transmission pipelines constructed before 1970 with an estimated economic life of 60 years and those constructed post-1970 with an economic life of 80 years. No such distinction was made in respect of compressor stations, where rotating equipment was said to have an economic life of 25 years in station facilities, odorizing stations an economic life of 35 years, and regulation and metering stations an economic life of 50 years.

The revised Access Arrangement Information, where this opinion is found, does not give the source of the information on which AGL relied, nor is there any explanation of the significant difference in the economic life of pipelines constructed before 1970 and those constructed afterward.

The ACCC relied in particular on sec. 8.1(a) of the Code, which provides that the service provider should have the opportunity to earn revenue that recovers the efficient cost of delivering the referenced services over the expected life of the assets used in delivering that service. In this case, the ACCC also noted that the proposed depreciation framework was feasible only because of the likely alternative pipeline.

Moomba to Sydney Pipeline

On 5 May 1999, East Australia Pipeline Ltd. (EAPL) submitted a proposed Access Arrangement for approval under the National Code in respect of the Moomba to Sydney Pipeline. The pipeline extends 1,299 kilometres from Moomba in South Australia to Wilson on the outskirts of Sydney, as well as pipelines from Young to Lithgow, Young to Culcairn, Junee to Griffith and Dalton to Canberra.

On 11 August and 21 September 2000, the Australian Pipeline Trust (APT) submitted proposed revisions as the new owner of EAPL.

Capital Base

EAPL assumed an economic life of 60 years for the Moomba to Wilson section and 80 years for other sections. The shorter life was assumed because of deterioration from stress, corrosion, cracking and the different coating technology used in construction.

Subsequently, APT submitted that by re-coating the pipeline in areas of deterioration, the economic life of the Moomba to Wilson section could be extended to 80 years, with those works to be carried out between 2033 to 2056 at a cost of $140M.

After substantial consideration of the matters included in the alternative methodology, the ACCC concluded that both the sale price of the asset and DORC valuation could be reasonable bases to establish the value of the initial Capital Base. The ACCC noted that the DORC value at $666M was substantially higher than a sale price basis for valuation but the DORC value assumed asset lives well in excess of those contemplated by TPA and EAPL in establishing third party tariffs on purchase of the pipeline.

The ACCC chose to adopt the asset life of 50 years as the more appropriate depreciation benchmark in calculating the DORC value. After adjustments for deferred tax liabilities, the value of the initial Capital Base was reduced to $502.1M.

Depreciation

EAPL originally proposed a kinked depreciation schedule – 62.5 per cent over the first half of the remaining economic life of the asset and 37.5 per cent over the second half. EAPL claimed significant stranded asset risk due to competition as the justification for accelerated depreciation.

As noted above, EAPL estimated economic life of 60 years for the Moomba to Wilson section in contrast to 80 years for the balance of the pipeline. A subsequent submission by APT proposed a straight-line depreciation and a yet further submission proposed extending the life of the Moomba to Wilson section through refurbishment.

The ACCC noted that for the future Access Arrangement period, section 8.9 of the Code required that the initial Capital Base be indexed for inflation from the commencement of the expired regulatory period, a deduction for indexed depreciation, adding new facilities investment (also indexed) and deducting redundant capitalin order to determine the Capital Base for the new regulatory period. This is the mechanistic reading that prohibits any revaluation of the assets comprising the initial Capital Base, and permits only adjustment for depreciation.

The ACCC rejected the proposed kinked depreciation and imposed indexed straight-line depreciation. The ACCC also included an amount for “Additional Depreciation” to “normalise tax payments. By this process future tax liabilities are spread over the life of the assets to avoid discontinuity in revenue from impacting on tariffs as taxes become payable in the future. In effect, this factor allowed a higher initial depreciation allowance, or return of capital, to offset the expected tax liabilities.

This is a further example of the willingess of the ACCC to adopt a flexible approach in adjusting the return of capital for risk by creating an extra depreciation allowance.

6.11.2 South Australian Decision

Moomba to Adelaide Pipeline System (MAPS)

On 1 April 1999, Epic Energy South Australia submitted an Access Arrangement for MAPS. This pipeline is presently the only pipeline bringing gas into South Australia. There is currently excess demand for gas in South Australia with proposals by Duke and Origin to meet that demand.

Capital Base

The DORC for the Capital Base was set at $353.3M as at 30 June 2001. In its Access Arrangement Information, Epic Energy stated:

> "The Pipeline System (PS) is now 29 years old. Given the appropriate on-going maintenance, it should operate for at least a further 50 years. For the purpose of evaluating DORC, the Pipeline System has been depreciated as a whole on that basis."

This statement implies an average economic life of 79 years for the system assets as a whole, without differentiation of asset classes or categories. This assessment proceeds on the basis of maintenance practices, rather than any other stated considerations.

In an issue paper produced for public consultation, the ACCC identified issues concerning depreciation including whether:

(1) the depreciation schedule satisfy the design objectives set out in section 8.33 of the Code; and

(2) 79 years is a good estimate of asset life of MAPS for the whole pipeline system; and

(3) the useful life of various segments or facilities of the pipeline system should be considered separately.

The ACCC retained Connell Wagner Pty. Ltd. to undertake a desktop audit of the DORC valuation supplied by Epic. That report recommended disaggregation of the pipeline system for depreciation by asset class. Connell Wagner estimated that by applying depreciation to the entire asset base as a whole, assuming a total asset life of 79 years, DORC valuation could be overstated by as much as 21 per cent. Epic retained Stephen Timms Consulting to review the Connell Wagner Report. Relevantly, Epic proposed a weighted average-life-of-all-assets approach. Using this approach and weighted whole-of-system-assets, asset life was estimated at 77 years and the pipeline life extended by 4 years to 81 years, giving a remaining pipeline life of 51 years. Epic argued that these economic lives were within justifiable technical and economic lives, given its past and future asset maintenance practices.

The cost of replacement of the pipeline was controversial in this Access Arrangement and, relevantly, consideration was given to the depreciation methodology.

In its consideration of this aspect, the ACCC initially referred to the requirement of Section 8.33 of the Code prescribing the design of the Depreciation Schedule for regulatory purposes. The ACCC stated that it favoured depreciation by asset class and referred to the statement in the Connell Wagner Report that this approach offers a more transparent and robust process. The ACCC therefore rejected the weighted average asset life approach proposed by Epic as being insufficiently transparent to track movements and assets over time, particularly making difficult the linking of capital expenditure to the expiry of assets.

The ACCC also considered a statement in the report by Stephen Timms Consulting that the economic life of the majority of rotating equipment in meter stations and compressor stations would be equal to the economic life of the pipeline. Epic submitted that its maintenance program ensured its assets would continue to fully meet original design requirements and, in effect, the economic life of the pipeline was continuously reset as maintenance was carried out and components were replaced.

Put another way, Epic submitted that the pipeline was so maintained as to continuously perform to design parameters and thereby its remaining life was constantly extended. Epic adopted a narrow physical life approach and relied heavily on the physical condition of its transmission assets and the operational and its maintenance expenditure. Taken to its logical extreme, this proposition would mean there is no specific economic life of gas transmission assets because physical life is continuously extended by maintenance.

The ACCC took the conventional approach to depreciating by asset class at a particular value of the asset base on a certain date.

Effective Asset Life

Following on from the above discussion, the ACCC considered the requirement of section 8.33(b) of the Code that an asset forming part of a covered pipeline should be depreciated over its economic life. The ACCC highlighted the proposition that economic life may differ substantially from technical life and factors other than the physical condition of the pipeline may operate to limit an asset's usefulness.

The ACCC observed that Epic did not distinguish between technical and economic life at any point of its valuation although it did raise concerns about financial risks associated with operating MAPS. Epic identified declining Cooper Basin gas reserves, increased electricity input into South Australia and by-pass/competition risks. In dealing with declining gas reserves, the ACCC said:

> "A decrease in gas reserves has the potential to limit the remaining economic life of the pipeline. The Commission understands that advice to the Victorian transmission systems owners took this fact into account in arriving at depreciated values (pre-privatisation) for the pipeline system in that state."

This comment appears to refer to the advice contained in the Saturn Report.

Epic raised concerns regarding uncertainty about remaining gas reserves having the potential to reduce demand for access to MAPS. The ACCC countered these concerns by referring to the possibility of using MAPS for gas transmission from northern Australia into South Australia. It observed that there was some constraint on the availability of gas from eastern states due to high demand for gas sourced in Victoria.

Relevantly, the ACCC stated that:

> "… while the factors outlined above have the potential to reduce the utilisation of MAPS at times in the future, they do not demonstrate that its economic life will be anything substantially less than the order of time assumed by Epic."

It seems clear that the ACCC took this view because of the lack of detailed analysis submitted regarding depletion of reserves in the Cooper Basin and any reduced demand as a consequence. The information on which Epic relied is found in Schedule 5 to its Access Arrangement Information. On analysis, this material contains general commentary on influences on the demand for gas haulage services in MAPS and assertions regarding uncertainty as to forecast level of demand in the short term (comprising the Access Arrangement) and the medium term beyond. In view of the generality of these matters, it is not surprising that, the ACCC did not accept this material as evidence justifying reduction of economic lives for the MAPS assets. Relevantly, the ACCC did however concede that, in principle, depletion of gas reserves could reduce economic life of transmission assets.

The ACCC proceeded on the basis that the MAPS pipeline system had an economic life of 80 years based on technical lives for pipeline assets referred to in the Connell Wagner Report as well as Epic's own view on the technical life of its system assets. The ACCC assumed an economic life of 30 years for compressors and 10 years for metering stations.

The Riverland Pipeline

Investra Ltd. owns gas distribution infrastructure assets in South Australia, Victoria, Queensland and Northern Territory. It also owns the Mildura Pipeline from Berri to Mildura. Mildura Pipeline interconnects with the Riverland Pipeline. Investra submitted Access Arrangements for each of its pipelines. The Riverland Pipeline was constructed in 1995.

Capital Base

Investra adopted DORC methodology and calculated the Capital Base as at 1 July 1999 at $15.25M. Investra purchased the Riverland Pipeline from Boral Energy on 1 July 1997. The pipeline entered in its books at a value of $15.409M. Adjusted on a value for depreciation calculated on a straight-line basis, the asset value was $15.018M as at 1 July 1999. This is very close to the DORC valuation of $15.25M.

Depreciation

Investra's straight-line depreciation was based on the asset lives adopted in the DORC asset valuation to establish its Depreciation Schedule. Investra said that the commencement of each Access Arrangement period, it would review asset lives and depreciation rates to reflect changes in technology and/or new information about the condition of the pipeline.

Investra adopted asset lives of 80 years for transmission lines and 50 years for gate stations and meters.

Northern Territory Gas Pipeline – Amadeus Basin to Darwin Pipeline

On 25 June 1999, NT Gas submitted an Access Arrangement for the Amadeus Basin to Darwin Pipeline (ABDP). Almost all (97 per cent) of the gas transmitted in the ABDP is used for electricity generation. The ABDP is fully committed to users under pre-existing transportation contracts and the Access Arrangement decision therefore had insignificant short term impact for existing users.

Capital Base

The DORC of the pipeline system was highly problematic in this case. The DORC proposed by NT Gas was independently reviewed by Connell Wagner. Subsequently, Venton & Associates was engaged to comment on the report of Connell Wagner. In turn, Connell Wagner reviewed Venton's comments. The ACCC conducted its own assessment based on both reports and other available material.

The relevant issue under consideration was the treatment of depreciation since 1986. Three alternative approaches were proposed. All assumed that the technical life of the pipeline was 80 years. NT Gas proposed accelerated depreciation of the initial Base because of concerns about the sustainability of then current return over the life of the pipeline. The reason for this concern is in the expiration of its foundation contracts in 2011, uncertainty about future production capacity of the Amadeus Basin and the potential for Timor Sea Gas to enter the Northern Territory.

The Draft Decision accepted arguments around these issues and proposed to depreciate the pipeline assets to a residual value in 2011. Thereafter, depreciation would be calculated on a straight-line basis over the remaining economic life of the assets, namely to 2066.

NT Gas evaluated its initial Capital Base using DORC methodology. Asset life assumptions used by NT Gas were, as stated above are:

- 80 years for transmission pipeline assets constructed in 1986 (average life remaining at 1 July 1999 67 years);
- 35 years for compressor stations (remaining economic life 22 years);
- 50 years for compression and metering stations (average remaining economic life 37 years); and
- 35 years for odorizing stations (average remaining economic life 22 years).

The Connell Wagner Report considered a number of approaches to depreciation and disagreed with the approach of NT Gas.

Connell Wagner recommended:

- kinked depreciation from pipeline commissioning in 1986 until 2011;
- post 2011 straight-line depreciation over the remaining technical life of the pipeline.

Connell Wagner also considered that the redundancy risks highlighted by NT Gas were possibly in existence since the initial planning, construction and operation of the pipeline, and therefore doubted that depreciation based on an 80-year life would be appropriate.

It reaching its preferred option, Connell Wagner factored in:

- the limited reserves of the Amadeus Basin;
- the foundation transmission contract due to expire in 2011; and
- possible reduced usage of the pipeline on entry of Timor Sea Gas,

and concluded it would be reasonable to expect that pipeline tariffs would be geared to recoup costs of assets over a shorter period.

Connell Wagner applied its own asset life assumptions to calculate the DORC value. And adopted the following:

- pipeline facilities 70 years;
- rotating equipment 30 years;
- metering equipment 50 years; and
- other pipeline facilities 15 years.

Relevantly, the ACCC expressly noted that NT Gas calculated depreciation in its DORC valuation by reference to technical lives, and thereby assumed that the technical life of an asset corresponds to its economic life. Implicitly, this comment recognises the potential for difference due to risk factors.

The ACCC concluded there was a risk of stranding faced by the pipeline evident during its construction. Factoring this risk led the ACCC to conclude that the appropriate valuation of the assets was below that in the DORC valuation by NT Gas. There was evidence given to the ACCC that proven probable reserves for the Amadeus Basin could only supply the demand for gas in Northern Territory until 2015. The reserves were reduced in confidential reports provided to the ACCC.

The ACCC concluded that uncertainty about reserves was known for a number of years, there was a risk of stranding evident since pipeline commissioning in 1986, and the earning potential of the pipeline was likely to be significantly reduced by 2011, the expiration date of the foundation transmission contracts.

The ACCC therefore re-assessed the DORC. One consideration in doing so was estimating the remaining economic life of the pipeline assets. In doing so, the ACCC again referred to account being taken of the potential decrease in gas reserves (presumably another reference to the Saturn Report) to limit the remaining economic life of Victorian gas transmission assets. The ACCC observed that a reduced economic life would typically result from a risk of stranding.

These considerations did not move the ACCC to adopt a reduced economic life for the NT Gas assets in this case and should therefore be seen as an exploration of matters of general relevance to the task of estimating depreciation and economic lives of regulated assets.

Instead, the ACCC chose an alternative approach and allowed for the reduced economic potential of the pipeline assets. The ACCC adopted the economic lives estimated by the DORC valuation but assumed:

- accelerated depreciation of the 12 years from 1999-2011 for pipeline assets;
- continued, if significantly reduced, transmission throughput until the end of the technical life of pipeline assets; and
- the possibility that the pipeline may be used to back-haul Timor Sea Gas from Darwin.

This last point fortified the ACCC in its opinion that the pipeline would continue to hold economic value after 2011, albeit a limited value, and its economic life would not expire until substantially later.

Importantly, the ACCC said it would review this matter in subsequent Access Arrangements when more information became available on the future use of the pipeline.

This case is an example of the methodological flexibility adopted by the ACCC in the exercise of its overall discretion in applying the Code to establishing the valuation of an initial Capital Base. Importantly, it illustrates that the choice of economic lives and the bases for depreciation can be particularly contextual and the ACCC recognises and accepts that there are factors that can reduce the economic life of assets to a period less than the technical or design life.

In this case, the ACCC responded to concerns about future gas reserves, and took those considerations into account in calculating the initial asset base, and equally importantly, stated its willingness to review an initial assessment in the light of further information, either on application by the transmission asset owner or on regulatory reset.

6.11.3 Western Australian Decisions by Independent Gas Pipelines Access Regulator (OffGAR)

Dampier to Bunbury Natural Gas Pipeline

On 15 December 1999, Epic Energy (WA) Transmission submitted a proposed Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline for approval under the National Access Code. In Western Australia, the National Access Code is incorporated into the Gas Pipelines Access (Western Australia) Law.

Capital Base

The Regulator determined the Base for the pipeline to be a DORC value of $1,233.66M as at 31 December 1999.

Depreciation Schedule

In its Depreciation Schedule, Epic Energy proposed depreciation schedules for each of four classes of assets comprising the pipeline assets. Epic Energy calculated depreciation on the values of physical assets using the annuity method.

Epic Energy proposed depreciation of assets based on the following asset lives:

- pipeline assets – 100 years (average remaining life 86 years);
- compression assets – economic life 57 years (average remaining life 49 years);
- metering assets – economic life 71 years (average remaining life 63 years); and
- other assets – economic life 50 years (average remaining life 39 years).

The Regulator concluded that these asset lives were excessively long and should be revised to be consistent with common industry assumptions for gas transmission pipelines.

In the course of submissions to the Regulator, Western Power and AlintaGas submitted that the asset lives assumed by Epic Energy were incorrect. In particular, AlintaGas submitted that the expected economic life of the pipeline was 65 years. The Regulator considered that the industry assumed lives for pipelines of 70 years, for compression assets of 30 years, for metering assets of 50 years and for other assets of 30 years.

It is not clear how the Regulator arrived at the conclusion that these lives are those commonly assumed in the gas transmission industry. They are, for example, inconsistent with a "normal" design life of 80 years adopted in a number of cases by the ACCC for pipeline assets. To approve the Access Arrangement, the Regulator required an amendment that the Depreciation Schedule reflect altered economic lives based on either annuity depreciation or straight-line depreciation as specified in his Draft Decision.

Goldfield Gas Pipeline

The Goldfield Gas Pipeline (GGP) was constructed between 1994 and 1996 pursuant to an agreement entered into between the state government of Western Australia and joint venturers. Until 1 January 2000, that agreement governed access to capacity in the pipeline by third parties. The Regulator assessed the proposed access agreement under the National Access Code.

Capital Base

GGP proposed a Capital Base for the pipeline, based on DORC methodology, at $452.6M. GGP did not estimate the DORC value by applying the conventional approach, but used depreciated adjusted historical costs to estimate DORC.

The methodology used was to adjust the actual construction costs for inflation, for interest cost during construction, for foreign exchange variations and then to depreciate the resulting value. The Regulator decided to use depreciated actual costs rather than DORC or other alternatives.

Depreciation Schedule

GGP proposed that the economic life for the Goldfields Gas Pipeline was equal to a regulatory life of 40 years based on a licensing period of 42 years less 2 years for pipeline design and construction when there was no revenue earned.

The Regulator disregarded the license period in making assumptions as to asset lives for the purposes of depreciation. The Regulator concluded that a weighted average asset life of 65 years was appropriate. The assumed lives are as follows:

- pipelines – 70 years;
- metering assets – 50 years;
- compression assets – 30 years; and
- other assets – 30 years.

6.11.4 Further Comments on Proposed Asset Lives

There were a number of submissions to the Regulator on the estimated asset lives. In the result, the Regulator concluded that GGP had not demonstrated any reasonable likelihood of events that would justify accelerated depreciation from:

- uncertainty about renewal of existing transmission contract; or
- contract existing in 2016.

A number of submissions to the Regulator expressed confidence in future demand for gas transmission services for the pipeline over a period of 30-50 years, and argued that because the pipeline could be connected to the Dampier-Bunbury Natual Gas Pipeline, depletion of reserves was inconsequential.

The Regulator obtained the report from a technical consultant that the estimated technical lives of the principal pipeline assets are:

- pipeline and laterals – 70 years;
- compressor stations and receipt and delivery stations – 30 years;
- metering stations – 50 years; and
- mainline valves – 50 years,

effectively the same as the “standard” lives assumed by the Regulator.

The Regulator calculated a weighted average asset life of 65 years for the pipeline based on the above averages.

6.12 Queensland Gas Derogations

In line with other states, Queensland was a signatory to the National Natural Gas Pipeline Access Agreement. Its implementing legislation, the Gas Pipeline Access Act (Queensland) 1998, came into effect on 19 May 2000.

That Act established certain derogations from the National Gas Code. One of these derogations is that Reference Tariffs over transmission pipelines are not reviewable by the ACCC for an extended period. The relevant pipelines are the Roma to Brisbane pipeline and the Carpenteria gas pipeline.

As a result of the derogations, the ACCC has jurisdiction to require amendments to the Access Arrangement with respect to non-tariff elements only. The Reference Tariff and Reference Tariff Policy, reference service and review date have been determined by the Queensland government for the initial Access Arrangement period.

6.13 Draft Regulatory Principles and Electricity Cases

The ACCC is the Regulator under the National Electricity Code (NEC). Its decisions concerning price caps for electricity transmission tariffs are relevant to consider, as they constitute a guide to current ACCC practice in the formulation and application of the Draft Regulatory Principles. They are not formally principles to be formally taken into account in determining Access Arrangements under the gas codes. Their significance lies in the expression of an underlying philosophy of the ACCC in the delivery of consistent and transparent regulatory policy across the several jurisdictions in which the ACCC is the regulator.

6.13.1 The Regulatory Framework

The National Electricity Market (NEM) commenced on 13 December 1998, establishing a single wholesale market for electricity in New South Wales, Victoria, Queensland, South Australia and the Australian Capital Territory. The NEM is governed by the NEC. The ACCC commenced regulation of transmission revenues in the NEM from 1 July 1999 and will cover all jurisdictions by 1 January 2003.

The ACCC determines the revenue caps to be applied to the non-contestable elements of participating transmission networks. Those revenues, combined with the revenues of the contestable networks, represent the network charges. The purpose of the revenue cap is to establish the maximum allowable revenue (MAR) owners can earn from the use of regulated assets. Contestable services derived from those assets are excluded from the revenue capping process because, being derived from a competitive environment, they can be separately determined by the asset owners.

The ACCC will progressively assume responsibility as regulator of the National Electricity Market. All transmission networks will come under ACCC regulation by 31 December 2002.

The first decisions made by the ACCC electricity regulator were made in respect of revenue caps for the non-contestable element of the New South Wales and Australian Capital Territory transmission networks – as respectively, the transmission assets of TransGrid and those of Energy Australia.

These revenue caps commenced on 1 July 1999 and apply for a period of five years to 30 June 2004. Clauses 6.2.2 through 6.2.5 of the Code prescribe the principles and objectives for the regulatory regime under the control of the ACCC.

6.13.2 Draft Regulatory Principles

As contemplated by the NEC, the ACCC has developed (although in draft form to date) a set of guidelines called the "Draft Statement of Principles for the Regulation of Transmission Revenues (Draft Regulatory Principles). The Draft Regulatory Principles find their origin in the provisions of clause 6.2 of the NEC. They are statements of the ACCC's intentions regarding the regulation of the respective revenue caps but are not intended to be, nor are they, legally binding. They are statements of a preliminary or initial position taken by the ACCC on the respective issues covered. The ACCC expects that its initial or draft approach may be modified in the light of experience. The ACCC expects to change the status of the document from draft to a more conclusive status before 1 January 2003, when it finally is the Regulator of the entire NEM.

The Draft Regulatory Principles are based on an accrual building block approach, using forecasts of the cost of the service over the regulatory period. That building block approach calculates a maximum allowable revenue (MAR) being the sum of the return on capital, the return of capital and operating and maintenance expenditures.

6.13.3 Asset Valuation Principles

Of the alternative methodologies available, the ACCC chose a DORC methodology to establish the initial valuation of a regulated Asset Base. It has also stated that it prefers this methodology in establishing the value of the initial Capital Bases in Access Arrangements for gas transmission assets under the codes.

The terms of clause 6.2.3(b)(4)(iv) of the NEC require the ACCC to have regard to the principles established by the Council of Australian Government of 19 August 1994, that deprival value should be the preferred approach for valuing network assets.

The NEC allows for existing network assets to be re-valued. The ACCC has taken the view that it must, consistently with the requirements of the NEC, give transmission and distribution asset owners the opportunity at the start of each regulatory review to identify assets that are subject to by-pass risk and to nominate the amount of a re-valued Asset Base on that account. Such assets will be subject to accelerated depreciation prior to removal from the regulated Asset Base.

6.13.4 Return of Capital

The building block approach to determine the MAR recognises that service providers are entitled to recover the capital costs expended in the purchase of assets in the regulated Asset Base and that such recovery amounts to depreciation over the useful life of the relevant asset.

In deciding on the approach to such depreciation, the ACCC proposed to adopt competitive depreciation rather than traditional straight-line depreciation. The principal reason for this choice was that, when larger assets are introduced to replace assets at the end of their useful life, there is a gap in capital revenues.

Relevantly, the proposed competitive depreciation profile is adopted in order to smooth revenue paths to avoid price spikes and to make adjustments to reflect the risk of possible redundant assets.

6.13.5 Valuation of transmission assets under the Code

Clause 6.2.3(d)(4)(iii) of the NEC requires that the transmission assets in service on 1 July 1999 are to be valued at the value determined by the Jurisdictional Regulator. The Code permits the ACCC to independently verify the opening asset value by an independent valuation process.

The NEC does not prescribe a mandatory methodology for the valuation of assets comprising the opening asset base. Clause 6.2.2(d)(ii), the relevant section of the Code, merely states that the value of those assets must "not exceed their deprival value". Clause 6.2.2(d)(iii) requires asset valuations undertaken by the Commission to be "consistent with COAG decisions". The deprival value of a transmission asset is the measure of the economic loss the network owner would suffer if deprived of the use of that asset.

There appears to be a broadly agreed view that this is generally taken to be the lower of the Depreciated Optimised Replacement Cost (DORC) or the economic value of the asset, where the economic value is the present value of the future revenue stream derived from use of the asset. In turn, the Draft Regulatory Principles impact upon the assessment of deprival values.

6.13.6 The legal effect of the Draft Regulatory Principles

The Draft Regulatory Principles are not legally binding. They represent a statement by the ACCC of how it proposes to regulate revenues from transmission assets in the long term. The ACCC has said that it expects its views may change over time as its experience in the jurisdiction increases.

6.13.7 Valuation of the Capital Base

So far as the valuation of an initial regulatory asset base is concerned, there is only one formal legal requirement emanating from the decision made by the Council of Australian Governments in 1994, and reflected in the Code, namely, that deprival value is the preferred approach in valuing network assets.

Except for the guidance provided by that provision, the ACCC would appear to have a broad, if not unlimited, discretion to choose an asset valuation methodology in respect of existing and new assets. The position is otherwise in respect of the valuation of assets for the first regulatory review.

Subject to Clauses 6.2.3(d)(4)(i) and (ii) of the NEC, any valuation of any new assets and any subsequent valuation of assets existing and generally in service on 1 July 1999 may be undertaken by the ACCC having regard to the elements set out in Clause 6.2.3(d)(4)(iv)(A) – (C) of the Code.

It is noted that the proposed statement S4.2 of the draft regulatory principles provides that ACCC will conduct a depreciated optimised replacement cost (DORC) valuation to establish the maximum value of the asset base as at the review date. These re-valuations and resets are to be conducted according to a pre-disclosed DORC guideline. The Commission expects that such a guideline will be developed prior to 31 December 2002. The ACCC states that where it conducts an asset re-valuation it will produce a report that will show the derivation of the valuation of the assets and the assumptions made.

The DORC methodology establishes the gross current replacement cost of modern equivalent assets, adjusted for over-design, for over-capacity and for redundant assets and then depreciates this value to reflect the anticipated effective working life of the asset from new, the age of the asset and the estimated residual value at the end of the asset's working life.

It is problematic how the values for anticipated effective working lives of the asset from new and the estimated residual value are to be assessed.

6.13.8 Changes in the value of assets – Proposed statement S5.5

The ACCC proposes that depreciation will be linked to the change in regulatory asset values, in nominal terms, during the regulatory period (with the exception of redundancy write-downs). Such changes will be calculated according to the competition depreciation approach taking into account likely changes in a DORC based valuation of the regulatory asset base. That valuation will require an assessment of technological change and potential by-pass threats to be provided by the asset owner.

6.13.9 Opening Asset Bases for NSW and ACT Transmission Network Revenue Caps

The NEC limits the discretion of the ACCC to decide an opening value for existing asset bases introduced into the jurisdiction of the NEC. The principal limitation is that the value must not exceed the deprival value of the relevant assets. Deprival value is defined in the NEC as the lesser of the assets' DORC or its economic cost. During the opening asset base valuation for Transgrid assets, the ACCC considered asset valuation information provided by the NSW government, and valuation reports obtained from GHD and SKM. The GHD Report concluded that the asset lives for Transgrid assets were generally in accordance with NSW Treasury guidelines. GHD did, however, recommend that the undifferentiated asset groups should be disaggregated to reflect the different asset categories within groups.

The SKM Report was obtained in order to review the GHD valuation. Relevantly, SKM concluded that there was no universal agreement on asset lives to be applied to the subject assets but that those used by Transgrid were within the range of lives used by other transmission bodies. As was the case in ascertaining historic costs of Victorian gas transmission assets, it was difficult to ascertain historic costs for these opening assets because it was not practicable to reconstruct an historic cost register.

Significantly, the ACCC noted, for the purposes of regulatory consistency, that it would be desirable to determine and apply standard lives to transmission assets across the national electricity market jurisdictions.

6.13.10 The Queensland Transmission Network Revenue Cap

The ACCC determined the revenue cap for the Queensland Transmission Network assets operated by Power Link commencing from 1 January 2002. The regulatory period is a period of 5-1/2 years in order to bring Power Link's regulated period in line with its financial year.

The parallel network assets owned and operated by Ergon Energy and Norgex, which are regulated by the Queensland Competition Authority, are not the subject of this cap decision.

In accordance with its regular practice, the ACCC retained a consultant valuer to provide a report on the opening value of the asset base. In this case, PB Associates was retained to undertake a review of the 1999 jurisdictional regulator's valuation, an independent DORC valuation from a consortium of valuers, Arthur Andersen, Gutteridge, Haskins & Davey, and

Worley. This consortium valuation was prepared for the former Queensland Energy Reform Unit as at 1 July 1999, a valuation date two years earlier than the date of the valuation of the opening asset base for this revenue cap decision.

The consortium valuation included an assessment of the effective life of Power Link's assets through an examination of asset service records, physical inspection and benchmarking, allowance for environmental conditions, intensive use and maintenance schedules.

Relevantly, the PB report reviewed the asset lives in the consortium valuation, noting that those asset lives were supplied by Power Link. PB compared those asset lives with those prescribed under NSW Treasury guidelines, by Transgrid and by the New Zealand Ministry of Economic Development and by PB Power in respect of United Kingdom electricity transmission assets. Curiously, only New South Wales' and overseas asset lives were used. It is unclear why asset lives adopted by other Australian service providers and regulators were not relevantly considered. The same approach was taken by PB in its report on the valuation of the Snowy Mountain Hydro-Electric Authority assets.

In general, the PB Report concluded that the asset lives employed by Power Link were consistent with those used in the other (foreign) jurisdictions for comparisons. It is significant that the ACCC regarded general consistency with other asset lives as an appropriate base for regulatory asset valuation purposes. As with all comparisons, it is important to ensure like is compared with like. In the above cases, asset lives adopted in New Zealand and England were used without, it seems, specific justification of their applicability or the preference for them over domestic comparisons in the Australian electricity transmission sector.

6.13.11 ACCC approach to setting the revenue caps

The ACCC adopted an accrual building block approach to determine revenue caps for TransGrid and Energy Australia. The building block approach determines the maximum revenue that a network can earn from its regulated assets on an annual basis.

The revenue cap is the sum of:

- a return on capital – the written-down or depreciated value of the asset base multiplied by the post-tax nominal weighted average cost of capital (WACC);
- the return of capital – depreciation allowance; and
- an allowance for operating expenditures.

6.13.12 Revenue cap for TransGrid

In its final decision, the ACCC recast the building block approach into a post-tax nominal formulation which it considered better reflected the ACCC's regulatory principles. The ACCC allowed for tax liabilities for expected business income tax payable, insurance for possible pass through of additional third party liability insurance costs, and the pass through effect of the GST. Regarding the initial asset base, the New South Wales Treasury obtained a consultant's valuation based upon DORC of the network assets and the ACCC engaged a consultant to review that valuation.

In respect of depreciation, ACCC made an allowance for "economic depreciation" which adds the negative straight line depreciation with positive annual inflation effects on the asset base so as to model the movements of asset values over the life of the regulatory period and to determine the return of capital. The calculation of the straight-line depreciation component was based on the remaining life per asset class. The draft decision on the revenue cap, the ACCC calculated depreciation on the basis of an initial asset value provided by the jurisdictional regulator, IPART, and on the assumption of an overall average remaining life of 25 years.

6.13.13 Revenue Cap for Energy Australia

The revenue cap determined by the ACCC for Energy Australia related to its parallel transmission network. The transmission services provided by Energy Australia are largely integrated with its provision of distribution services. This aspect was relevant in the assessment of operating costs and potential productivity improvements. In its draft decision, the ACCC estimated depreciation based on the valuation of assets by IPART into specific assets or class of assets by approximation. Energy Australia objected that this approach resulted in an under-estimation of the depreciation of transmission assets. The ACCC, in its Final Decision, based its estimate of depreciation upon a consistent disaggregation of values by asset class.

6.13.14 The Snowy Mountain Hydro-Electric Authority (SMHEA) Decision

The requirement under the Code that the ACCC must have regard to COAG agreement of 1994 that deprival value is to be the preferred approach to valuing network assets had a particular importance in the valuation of the SMHEA assets. This is because, if the National Electricity Market is deprived of the SMHEA transmission assets, inter-connection between New South Wales and Victoria would be effectively removed with a consequential profound effect on the NEM and competition levels. Accordingly, the deprival value of SMHEA transmission network assets should be clearly related to the benefits derived by end-users resulting from reductions in energy prices achieved through the introduction of the competitive electricity market. Deprival value could be assessed as high as equivalence to those benefits or substantially proportional to them.

Additional benefits from the inter-connection assets included a sharing of surplus generating capacity and reserves between New South Wales and Victoria, avoidance of the cost of new generation plant, the Victorian requirements for peak capacity being satisfied by New South Wales generation and network reliability and shared ancillary services.

The SMHEA transmission assets substantially facilitated the existence of the National Electricity Market and as such the deprival value of those assets facilitated the inter-connection between the two largest State markets.

Initial asset valuation

Prior to the revenue cap decision, there had been a number of valuations of SMHEA transmission assets using different methodologies and having different scope.

The ACCC engaged PB Power to review the most recent valuation, being a valuation of February 1999 prepared for the New South Wales Treasury by A consortium consisting of Arthur Andersen, Gutteridge Haskins and Davey and Worley International. PB Power was engaged to review the DORC cost valuation conducted by the consortium and, in particular, to review the assumptions, methodologies and findings in the valuation relative to consistency with the requirements of the Code in the valuation of network assets.

PB Power considered a report of the consortium valuation by Sinclair Knight Merz (SKM) in 1997. The SKM report included two valuations, one based on New South Wales Treasury guidelines and the other assuming a minimum remaining life of 20 years. PB Power stated that the difference between those two valuations illustrates that the DORC valuation is particularly sensitive to the asset lives assumed.

Application of effective lives in the DORC valuation

A comparison of the asset lives used for asset valuation purposes in different jurisdictions is given in the tables below reproduced from the PB Report.

Category	SMHEA	Treasury Guidelines	TransGrid
Transmission Lines Tower	50	50	50
Pole	-	35	50
Transformers	40	50	35 to 40
HV Switching Equipment	40	40	40
Controls/Protection			
Electromechanical	20	40	40
Electronic	15	-	-
Auxiliary & Ancillary Equipment	20	35-40	40

Category	TransPower NZ	Treasury Guidelines	Average life PB Power UK
Transmission Lines Tower	70 (inland)	50	68
Pole		35	53
HV Circuit Breakers			
Airblast	35	40	50
Auxiliary & Ancillary Equipment	20	35-40	40

The table provides a comparison of the asset lives used for asset valuation purposes in different jurisdictions, Transgrid, SMHEA and Treasury all in New South Wales and New Zealand and England, two foreign jurisdictions.

Transmission line asset lives

After a discussion of the environmental factors that can affect the life of steel tower transmission lines and conductors and fittings in transmission lines, PB Power considered that the 50 year asset life for steel tower lines determined by SKM was too short if the valuation was to be a fair reflection of economic deprivable value. PB Power proposed a useful life of 70 years. Alternatively, differentiating the components of a tower line into the conductors and fittings on the one hand, and the steel towers on the other, PB Power proposed a useful life of 80 years for the towers and foundations and 40 years for the conductors and fittings.

Switching station asset lives

PB Power compared the lives of components of the switching station assets with New Zealand and United Kingdom assessments. In the case of air blast breakers, PB reported the practice in New Zealand is to give a life of 35 years and the practice in the United Kingdom is to give a life of 50 years. New South Wales Treasury guidelines provided a life of 40 years. Based, PB said, on its experience, PB Power proposed extending the life of buildings from 40 years to 50 years and gear infrastructure and busbar life from 40 years to 50 years. Overall, PB Power suggested that an average switching station asset life of 45 years would be appropriate.

Relevance of the changes

PB Power estimated that increasing the life of the steel tower lines from 50 years to 70 years and increasing the life of switchyards from 40 years to 45 years increased the DORC valuation by approximately $16 million to a figure of $63 million - approximately 30 per cent. PB used comparisons of New Zealand and United Kingdom practice without detailed analysis of the comparability of environmental conditions.

The SMHEA had submitted to the ACCC that a number of factors including the difficulty of access to the transmission networks caused by the remote and rugged terrain, the stringent environmental planning and construction limitations occasioned by most of the transmission assets operating within the bounds of the Kosciusko National Park and the inclusion of access tracks pointed to a justified adoption of a high terrain factor to be incorporated into the asset base review. While those factors impinged specifically upon construction costs, they appear to be relevant generally to the issue of asset lives in alpine areas and it is surprising that PB Power did not specifically address those factors in recommending, without comment, the adoption of longer asset lives based upon New Zealand and United Kingdom practice.

In its Report, PB noted at page 14:

> "The Guidelines require that standard asset lives should be used except in "rare" cases where assets may have different useful lives because of different service conditions. Variations from standard lives are to be made in a transparent and consistent fashion, and justified and documented by the valuer."

There is much discussion within the industry as to the appropriate asset lives to use for valuation purposes and this is reflected in the tables below. Some of the reasoning behind the selection of asset lives is also discussed below. In the Consortium valuation, the TransGrid asset lives, as listed in the table below, were used.

It is apparent from the above table, relied on by PB to indicate the "industry discussion" on asset lives, that 50 years was adopted as the asset life for transmission lines in New South Wales by the Guidelines, SMHEA and Transgrid, with the New Zealand and UK jurisdiction adopting longer lives.

The ACCC accepted the recommendation of PB Power to increase the asset lives from 50 to 70 years in respect of the steel transmission line and from 40 to 45 years in respect to the switching stations. Accordingly, the ACCC set the opening asset base at $62.45 million, a figure slightly lower than the $63 million recommended by PB Power, the difference being attributable to rounding.

PB Power did not include reference to the existence of any industry standard or practice in the determination of effective lives for transmission assets in other jurisdictions in Australia, or point to the lack the lack thereof as the rationale for using asset lives adopted in foreign jurisdictions.

It is also worthy of note that the ACCC was prepared to accept its own consultant's recommendation for longer asset lives than those identified in the consortium report despite the absence of a comprehensive review of local "industry" practice and a clear reliance instead on asset lives adopted by regulators in New Zealand and the United Kingdom.

It is worthy of note also that reference the good condition of the assets was made in the PB Power report despite the acknowledged failure of any recent valuer to actually inspect them. Also, note is taken of the stated inability to identify the date upon which any asset was brought into use and the uncertainty about the vintages of assets – an instance reported by PB Power refers to a stated date of introduction that was 10 years later than the age recorded in the SMHEA's records.

The system security effects of the presence of the SMHEA assets for the Victoria/New South Wales grid were referred to but not analysed. Significant analysis on this factor was undertaken by the ACCC in the GPU GasNet Interconnect revision case under the Code.

6.14 Review of Access Arrangements

6.14.1 Code requirements

There is a common revisions commencement date of 1 January 2003 specified in each of the Access Arrangements. Clause 2.28 of the Code requires the Service Provider **must** "submit to the Relevant Regulator proposed revisions to the Access Arrangement together with the applicable Access Arrangement in Formation".

Clause 2.29 of the Code reads:

> "The Access Arrangement as revised by the proposed revisions may include any relevant matter but must include at least the elements described in Section 3.1 to 3.22".

Pursuant to Clause 2.35, the Relevant Regulator must issue a draft decision either approving the proposed revisions to the Access Arrangement or proposing not to approve those revisions, giving reasons for that proposal and amendments required to the revisions in order to obtain approval of them. There is a public advertisement and submission period in respect of both the initial consideration of the proposed revisions and in respect of the Draft Decision of the Relevant Regulator. The Decision must be made by the specified date either approving the revisions, not approving the revisions and giving reasons for that decision and stating amendments required to obtain final approval, or approving amended revisions submitted by the Service Provider which satisfies the amendments specified in the Draft Decision.

The Relevant Regulator may draft and approve its own revisions to the Access Arrangement if the Service Provider fails to submit proposed revisions as required under the Access Arrangement or fails to submit revisions incorporating the amendments required by the Relevant Regulator in its final decision.

In any event, Clause 2.43 of the Code requires the Relevant Regulator to issue a final decision within six months of receiving proposed revisions. This period may be extended by periods of up to two months on one or more occasions on publication of notice of a decision to increase that period.

6.14.2 The Content of Revised Access Arrangements

There are provisions in the Code which limit the discretion of the Relevant Regulator to approve proposed revisions. The current requirement is that they must contain the elements and satisfy the principles set out in Section 3.1 through 3.22 of the Code. Further, the proposed revisions must, to the satisfaction of the Relevant Regulator, satisfy the provisions of the Code generally, taking into account the broad policy considerations set out in Clause 2.24(b) of the Code as well as taking into account the provisions of the Access Arrangements themselves.

Pursuant to each Access Arrangement, the Revision Submission Date is 30 June 2002 and the Revision Commencement Date is 1 January 2003.

6.14.3 Determining the capital base on commencement of the next Access Arrangement period commencing on 1 January 2003

Division 8 of the Code sets out Reference Tariff principles to be applied in determining Reference Tariffs in an Access Arrangement.

Clause 8.14 of the Code provides that the capital base at the commencement of a new Access Arrangement period is the capital base applying at the expiry of the previous period but adjusted for New Facilities investment or the Recoverable Portion (whichever is relevant), Depreciation and Redundant Capital (as described in Section 8.9) as if the previous Access Arrangement had remained in force.

"Depreciation" is a defined term under the Code. It means:

> " 'Depreciation' means in any year and on any asset or group of assets, the amount calculated according to the depreciation schedule for that year and for that asset or group of assets".

"Depreciation Schedule" is also a defined term the meaning of which is in Section 8.32.to mean:

> "8.32 The Depreciation Schedule is the set of depreciation schedules (one of which may correspond to each asset or group of assets that form part of the Covered Pipeline) that is the basis upon which the assets that form part of the Capital Base are to be depreciated for the purposes determining a Reference Tariff."

The Code then goes on to state how the Depreciation Schedule should be designed in terms of Clause 8.33. That Clause reads as follows:

> "8.33 The Depreciation Schedule should be designed:
>
> (a) so as to result in the Reference Tariff changing over time in a manner that is consistent with the efficient growth of the market for the Services provided by the Pipeline (and which may involve a substantial portion of the depreciation taking place in future periods, particularly where the

calculation of the Reference Tariffs has assumed significant market growth and the Pipeline has been sized accordingly);

(b) so that each asset or group of assets that form part of the Covered Pipeline is depreciated over the economic life of that asset or group of assets;

(c) so that, to the maximum extent that is reasonable, the depreciation schedule for each asset or group of assets that form part of the Covered Pipeline is adjusted over the life of that asset or group of assets to reflect changes in the expected economic life of that asset or group of assets; and

(d) subject to section 8.27, so that an asset is depreciated only once (that is, so that the sum of the Depreciation that is attributable to any asset or group of assets over the life of those assets is equivalent to the value of that asset or group of assets at the time at which the value of that asset or group of assets was first included in the Capital Base."

The terms of sub-clause (b) above are significant in the reference to a requirement to depreciate over the economic life of the relevant asset or group of assets. "Economic life" is not a term that is defined for the purposes of the Code. Economic life is generally understood to mean the period over which an asset can contribute to the financial targets of its owner.

Sub-clause (c) is arguably the most significant provision here. This provision contemplates that changes can be expected in the economic life of a relevant asset, and the Depreciation Schedule should be adjusted to make provision for such changes.

To adjust the life of an asset or group of assets in respect of expected changes in their economic life, it is first necessary to determine (1) the basis on which economic life is properly to be determined and (2) to then make an assessment, **at a particular point in time** , of the probability of the happening of future events or circumstances that will impact on the then current (ie assessed at a previous point in time) assessment of the economic life of that asset.

The exercise in the case of the forthcoming regulatory reset is an assessment, as at 31 December 2002, of the probability of the happening of future relevant events and the likely effect such events will have on the economic lives of assets as assessed at the commencement of the Access Arrangement, namely 15 March 1999.

It should be borne in mind that GHD valued the transmission assets of the then owner, TPA, on the basis of the ODRC methodology as at 30 June 1997. Ernst & Young reviewed that valuation as to the commercial practices adopted in the valuation methodology and in particular, advised concerning certain assumptions made and the consistency of that methodology with the Victorian Government's objectives for establishing the Reference Tariffs.

The Access Arrangement Information, at page 11, states the assumptions on which economic lives were assessed as:

"(A) Estimates of economic lives are based on industry experience, pipe life research, standard maintenance practice and specific research undertaken by Saturn Corporate Resources Pty Limited. The report prepared by Saturn determined the extent to which remaining economic lives of the Transmission System would be impacted. It assessed the Transmission System in two components: one having an economic life up to 2030 and the remainder up to the year 2033.

(B) Remaining lives for all assets are calculated as the economic life less the estimated age of the asset.

(C) Minimum remaining lives are assumed for each asset type, indicating that when the asset has reached the end of its "standard" life, if it is still providing gas transmission service then some minimum value will be attributed to it."

Table 2.2(c)(4) (reproduced elsewhere in this report) records the economic life in years for transmission pipelines of the PTS and the WTS, respectively given as 38 to 60 years for the PTS and 37 to 47 years for the WTS.

6.15 Revaluation or Adjustment?

The ACCC has consistently stated that it will adopt the "mechanistic" approach to interpretation of Clause 8.14 of the Code and that the capital base cannot be revalued, merely permissibly adjusted for augmentation from New Facilities Investment and for diminution from Depreciation and Redundant Capital

The identification of redundant assets at the commencement of the new regulatory period by the service provider is clearly contemplated and where identified and accepted, will be the subject of accelerated depreciation and ultimate removal from the Capital Base.

Clause 8.33 (b) of the Code requires that, "to the maximum extent that is reasonable, the depreciation schedule for each asset or group of assets that form part of the Covered Pipeline is adjusted over the life of that asset or group of assets to reflect **changes in the expected economic life of that asset** or group of assets". (emphasis added)

It seems both consistent with this requirement, and also with the factoring of risks in the Rate of Return under clause 8.30, that where events occur during the course of a regulatory period that are not foreseen at its commencement and thereby are not taken into account in determining the depreciation schedule, that they are factored into the adjustment made on account of "changes in the expected economic life of that asset". The time to do so is when making the revisions required on reset for the next regulatory period.

The bases for agitating the probability that relevant factors exist, and quantifying their effect on the remaining economic lives of transmission assets, is problematic in general and may be controversial with the ACCC in particular.

6.16 Risks and The Rate of Return

In the course of reaching its final decision for the Access Arrangement, the ACCC was obliged to reconsider its assessment of the risk profile of the transmission business. It identified two types of risks:

- market risk, also known as systematic or non-diversifiable risk; and
- risk unique to a firm that can be diversified.

The capital asset pricing model approach used by the ACCC included an estimate of market risk, the equity beta, but did not include an estimate of unique risk. Interested parties made submissions arguing there should be an allowance for unforeseen events that affect the gas supply and result in temporary loss of revenue to the network owners. The ACCC mentioned the (then) recent Longford explosion and conceded that it may be theoretically sound to include unique risks in the cash flows but concluded that such risks are extremely difficult to quantify and are risks that are self-insured in the commercial world.

In determining the cost of capital for the revised WACC the ACCC made the following assessments.

- Longer term risk was limited due to the captive and relatively broad nature of the market, catastrophic risk aside as evidenced by the events at Longford.

- The risk of by-pass and stranded asset risk is limited by the characterisation of the Victorian transmission system as a “mature” pipeline system allowing the adoption of a market carriage model.

- There is a reduction in the risk profile of the pipeline asset owner because of the split in the ownership of the transmission system and the identity of the operator. In the case of the Victorian system, the owner is separated and is a different identity from the operator VENCorp. The risk profile is reduced because the regulatory limitations on the liability of VENCorp flow through to its administrative bodies, agents and employees acting in good faith.

- These arrangements provide for a regulatory asset base that is adjustable for inflation as well as CPI-X adjustment for tariffs between reviews. The reduction of the inflation risk reduces concerns for long term investment where that investment is based on heavy borrowing.

The ACCC also ventured the opinion that the National Code and the Code recognise that greenfield investment have higher risk factors, both in market and construction risks not inherent in existing mature assets. In particular the ACCC mentioned that new pipelines will be assessed differently in terms of overall risk than the mature Victorian system. Further, there are tender provisions in both the National Code and the Code in which a competitive rate of return is determined thereby taking account of special risks associated with a greenfields project.

In its determination in the Amadeus-Darwin Pipeline Access Arrangement, the ACCC has demonstrated that it will accommodate the risk profile of new pipelines in determining the depreciation profile and allow an adjustment to the revenue stream through accelerated depreciation rather than the alternative of reducing the economic life of the pipeline assets. It remains to be seen how the ACCC will regard claims for adjustment on regulatory reset due to new, or enhanced, risk of stranding/redundancy in respect of a more mature pipeline.

Appendix A: GHD Ltd technical life (TL) analysis of GasNet's transmission system

Pipeline Number	Asset Description	Pipe Diameter (mm)	Length (km)	Optimised Replacement Cost	Design Life	Year Commissioned	Life to Date	Remaining Technical Life
Parent List	*Parent List*	*Parent List*		*Parent List*		*Parent List*	*Calc*	
Element A	*Eastern System*						Report date	2001
T1	DANDENONG - Morwell (Ex Lurgi)	450	126.24	28,611,457	60	1956	45	15
T60	LONGFORD - DANDENONG (NORTHERN)	750	173.53	82,854,274	60	1969	32	28
T60	LONGFORD-ROSEDALE	750	30.42	13,726,743	60	1978	23	37
T60	ROSEDALE-TYERS	750	34.30	15,488,856	60	1978	23	37
T60	BUNYIP-PAKENHAM	750	18.67	8,416,716	60	1982	19	41
T63	TYRES - MOREWELL	500	15.64	4,832,800	60	1979	22	38
	WA			$ 153,930,846				28
Element B BSU	*South Western System*							
	SOUTH - WEST	500	143.9	$ 56,068,230	60	2000	1	59
BR								
	IONA - PAARATTE PIPELINE	150	7.8	1,928,970	60	2000	1	59
T81	PAARATTE - ALLANSFORD	150	33.25	4,056,455	60	1986	15	45
T86	ALLANSFORD - PORTLAND	150	100.38	12,393,903	60	1993	8	52
T91	CURDIEVALE - COBDEN	150	27.72	3,691,515	60	1994	7	53
T93	CODRINGTON-HAMILTON	150	54.54	6,554,136	60	1995	6	54
	WA			$ 28,624,979				52
Element C	*Rest of the System*							
T5	MORWELL - TRAMWAY ROAD	100	0.68	206,376	60	1962	39	21
T15	OAKLEIGH (CLYDE ST)	200	0.77	239,080	60	1966	35	25
T16	DANDENONG - WEST MELBOURNE	750	35.60	65,617,600	60	1969	32	28
T24	BROOKLYN - CORIO	350	50.53	19,238,743	60	1971	30	30
T25	SOUTH MELBOURNE (CECIL ST- PICKLE ST)	200	1.43	419,538	60	1969	32	28
T32	CRANBOURNE (POUND ROAD)	100	2.03	248,540	60	1976	25	35
T33	SOUTH MELBOURNE-BROOKLYN	750	12.74	24,183,400	60	1977	24	36
T37	MARYVALE (A.P.M.)	150	5.63	1,037,655	60	1971	30	30
T38	PAKENHAM (BALD HILL RD -HEALESVILLE KO	80	1.16	169,932	60	1972	29	31
T44	WARRAGUL - ANDERSON ST	100	4.79	786,572	60	1974	27	33
T56	BROOKLYN - BALLAN	200	66.60	10,448,156	60	1972	29	31
T57	BALLAN - BALLARAT (SOUTHERN)	150	22.69	2,806,067	60	1973	28	32
T57	BALLAN - BALLARAT (NORTHERN)	300	22.77	5,292,163	60	1982	19	41
T59	EUROA - SHEPPARTON	200	34.46	3,723,485	60	1976	25	35
T61	PAKENHAM - WOLLERT	750	93.01	76,164,039	60	1984	17	43
T62	DEER PARK - SUNBURY	150	24.18	3,800,575	60	1979	22	38
T64	NEWPORT (POWER STATION)	450	0.99	1,265,460	60	1980	21	39
T65	DANDENONG (HENTY ST)	750	5.02	8,351,000	60	1981	20	40
T66	MT FRANKLIN - KYNETON	300	24.56	5,204,246	60	1981	20	40
T67	GUILFORD - MARYBOROUGH	150	31.40	4,313,036	60	1980	21	39
T70	BALLAN - BENDIGO (WESTERN)	150	90.69	8,385,573	60	1973	28	32
T70	BALLAN - BENDIGO (EASTERN)	300	50.73	9,111,622	60	1981	20	40
T71	SHEPPARTON - TATURA	200	16.24	2,025,800	60	1981	20	40
T71	TATURA-KYABRAM	200	21.21	2,227,050	60	1982	19	41
T74	WOLLERT- WODONGA	300	269.17	67,196,945	60	1976	25	35
T75	WANDONG _KYNETON CITY GATE	300	59.47	10,451,830	60	1986	15	45
T85	KYABRAM - ECHUCA	150	30.63	2,665,090	60	1991	10	50
T88	LAVERTON NTH. CITY GATE - BHPP	150	1.62	180,731	60	1994	7	53
T89	PORT MELBOURNE (BOUNDARY ST)	150	0.44	111,020	60	1993	8	52
	MURRAY VALLEY PIPELINE	200	103.5	15,032,611	60	1999	2	58
	WA			$ 350,903,935				**37**

Notes:
1. WAL = Weighted average.
2. Where assets are still in operation past their T Life a standard 5 year RTL has been adopted. This is in keeping with the original Optimisation rules applied to the 1995 and 1997 valuations.

Appendix B: Reserve definitions

Reserve estimates are based on Australian Geological Service Organisation (AGSO), prior to 1999 the Bureau of Resource Sciences (BRS), and other agency and corporate sources. Reserve estimates by basin included the following reserve classifications used by BRS:

Category 1
Category 2; and
Undiscovered reserves

Category 1 reserves comprise current reserves of those fields which have been declared commercial. They include 'proved' and 'probable' reserves.

Category 2 reserves comprise estimates of recoverable reserves which have not yet been declared commercially viable; they may be either geologically proved or are awaiting further appraisal.

Together, Category 1 and 2 comprise **recoverable** reserves.

Undiscovered reserves are inferred from basic geological data at various probability (of reserves being discovered) levels, for example 5 per cent, 50 per cent and 95 per cent; levels decline as the probability increases.

Another reserve classification system used by BRS is the McKelvey system which provides estimates of economic and sub-economic reserves.

Economic reserves are resources judged to be economically extractable and for which the quantity and quality are computed partly from specific measurements, and partly from extrapolation of geological evidence. Sub-economic reserves are similar to economic reserves in terms of certainty of occurrence and, although considered to be potentially economic in the foreseeable future, these resources are judged to be sub-economic at present.

This system is also applied by AGSO/BRS but only in a minor role with the major emphasis being on the Category 1, Category 2 and Undiscovered reserves system.

If the latest (2001 preliminary) official recoverable estimates are used, the Gippsland (and other eastern basin) gas reserves will be virtually depleted by about 2020, necessitating supply from western and northern Australia at higher market-gate prices in eastern Australia. A second reserve case can be constructed; in this "actual reserves" (AR) case an estimate is made of ultimate recoverable reserves based on corporate sources and judgments of informed analysts. At the 0.5 probability level the depletion date for all eastern Australian reserves is about 2025 and between 2028 and 2032 for "Victorian" basins (Gippsland, Otway, Bass).

Gas reserves: historical assessment

The estimates of Australian gas reserves is based on the most recent data available from the Bureau of Resource Science (BRS) who publish official reserves data based on their own assessments and reports from companies and state agencies. The data thus provides a current assessment of reserves and is used as a base reserves case which covers the various classes of reserves (Category 1, Category 2 and Undiscovered reserves).

Many petroleum (oil, gas) analysts fell that this data does not represent the real recoverable reserve situation, pointing to the fact that reserves have not changed significantly over the past 20 years. In that time there has been significant resource use (about 3,000 PJ of gas from Gippsland), and there has been further exploration and resource assessment. To illustrate the point, note that in 1977 gas reserves in the Gippsland Basin as at 31 March 1977 were stated by the Bureau of Mineral Resources[8] (forerunner of BRS) to be as indicated in **Table B1**; comparisons with BRS 1995 estimates are also provided in **Table B1**.

This data indicates Gippsland Basin reserves, allowing for different reserve definitions have remained about the same over the period 1997-1995, a period when over 3,000 PJ of gas was extracted from the basin.

Cynical analysts might claim that the resource appears to be infinite in the Gippsland Basin, and reserves might well be the same in 2010 or even 2025. This **actual reserves** (AR) approach seriously questions the official reserves estimates, and even though gas is a non-renewable resource and some fields/basins have been depleted, suggests a very cautious approach should be taken on resource depletion.

Table B1 Gippsland Basin reserves: historical review

1977 BMR reserve estimation	
Proven and probable reserves	205.59 billion m^3
(approximates to Category 1 and part Category 2)	approx. 8,240 PJ
Theoretically recoverable reserves	36.71 billion m^3
(approximates part Category 2 and Undiscovered reserves)	approx. 1,480 PJ
Total	**approx. 9,720 PJ**
1996 BRS reserves (31 December 1995)	
Category 1	approx. 4,500 PJ
Category 2	approx. 3,500 PJ
Undiscovered – 25 per cent probability	approx. 1,300 PJ
Total	**approx. 9,300 PJ**

The major uncertainties in estimating ultimate recoverable gas reserves are:

- estimation of undiscovered, that is reserves in addition to Category 1 and 2 reserves; and

- economics of recovery which in turn depends on recovery costs and prices obtainable for recovered resources.

Estimation of undiscovered resources is undertaken by analysis of geological formations and probability analysis of the geological information; and economics of recovery are analysed by probability (discounting analyses of future costs and prices).

Experts in agencies and corporations differ significantly on the level of probability they choose to assess ultimate gas resources in Australia.

8 The Petroleum Newsletter, BMR, No. 69, 1977.

Analytical groups such as Saturn are in a dilemma when faced with this “evidence” and the need to model and analyse the future supply of a depletable resource. As indicated above, the ultimate depletion date for Gippsland Basin fields will significantly affect long term gas costs to major Victorian markets. Thus, even the highest cost (on current estimates) reserves from Gippsland are, because of their location relative to markets, likely to provide lower cost (real resource cost basis) market gas than gas from other basins.

Release of the 2001 AGSO report on *Oil and gas resources of Australia* has been imminent for some time. The Australian Gas Association (AGA) has obtained preliminary figures.