Final Decision

Access Arrangement proposed by NT Gas Pty Ltd for the Amadeus Basin to Darwin Pipeline

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Contents

Abbreviations and glossary of terms

ABDP	Amadeus Basin to Darwin Pipeline
Access arrangement	Arrangement for access to a pipeline provided by a pipeline owner/operator that has been approved by the regulator
ACG	Allens Consulting Group
ACQ	Annual Contract Quantity
AGA	Australian Gas Association
AGL	The Australian Gas Light Company
AGSM	Australian Graduate School of Management
Agility	Agility Management Pty Limited
AGLP	AGL Pipelines (NSW) Pty Limited
APT	Australian Pipeline Trust Limited
ATO	Australian Taxation Office
BHP	BHP Limited
CAPM	Capital Asset Pricing Model
The Code	National Third Party Access Code for Natural Gas Pipeline Systems
Commission	Australian Competition and Consumer Commission
Connell Wagner	Connell Wagner Pty Limited
Covered pipeline	Pipeline to which the provisions of the Code apply
CPI	Consumer Price Index
CWP	Central West Pipeline
DAC	Depreciated Actual Cost
DORC	Depreciated Optimised Replacement Cost
DRC	Depreciated Replacement Cost

Draft Regulatory Principles	*Draft Statement of Principles for the Regulation of Transmission Revenue*
EAPL	Eastern Australian Gas Pipeline Limited
Epic	Epic Energy (South Australia) Pty Limited
GJ	Gigajoule
GPAL	Gas Pipelines Access Law
GSA	Gas Sales Agreement
GST	Goods and Services Tax
ICB	Initial Capital Base
Issues Paper	ACCC Issues Paper on NT Gas' access arrangement for the Amadeus Basin to Darwin Pipeline
IPART	Independent Pricing and Regulatory Tribunal
IRR	Internal Rate of Return
KPI	Key Performance Indicator
LNG	Liquefied Natural Gas
MAOP	Maximum Allowable Operating Pressure
MAPS	Moomba to Adelaide Pipeline System
MDQ	Maximum Daily Quantity
MHQ	Maximum Hourly Quantity
MSP	Moomba to Sydney Pipeline System
Nabalco	Nabalco Pty Limited
NEC	National Electricity Code
NT	Northern Territory
NT Gas	The operator from time to time of the Pipeline which at 25 June 1999 is NT Gas Pty Ltd as trustee of the Amadeus Gas Trust
NTPG	NT Power Group Pty Limited (Power Generation and Transmission)

NTS	New Tax System
NPV	Net Present Value
O&M	Operating and Maintenance
ODV	Optimised Deprival Value
ORC	Optimised Replacement Cost
ORG/ESC	Office of the Regulator-General, Victoria Now referred to as the Essential Services Commission
PJ	Petajoule (equal to 1 000 000 GJ)
Phillips	Phillips Petroleum Company (Exploration & Production (E & P)) Limited
PWC	Power & Water Corporation, formerly Power and Water Authority (PAWA)
RC	Replacement Cost
Santos	Santos Offshore Australia Business Unit
Shell	Shell Development (Australia) Pty Limited
TJ	Terajoule (equal to 1 000 GJ)
TPA	Transmission Pipelines Australia Pty Limited
Venton & Associates	Venton & Associates Pty Limited
WACC	Weighted Average Cost of Capital
Woodside	Woodside Energy Limited

Executive Summary

Background

On 25 June 1999, NT Gas submitted to the Australian Competition and Consumer Commission an access arrangement for the Amadeus Basin to Darwin Pipeline (ABDP). It sought approval under the *National Third Party Access Code for Natural Gas Pipelines Systems* (the Code).

The ABDP transports gas from the Palm Valley and Mereenie gas fields to Darwin. The majority of gas (99.7 per cent) transported is used in the generation of electricity. The pipeline is fully contracted until 2011. AGL holds a 96 per cent interest in NT Gas.

The access arrangement describes the terms and conditions on which third parties will gain access to the pipeline. The Commission's assessment involved public consultation and an examination of information provided by NT Gas and interested parties. The Commission issued its *Draft Decision* on 2 May 2001, and undertook further public consultation in arriving at this *Final Decision*.

The Commission's assessment

This *Final Decision* relates to an access arrangement period of 10 years from **1 July 2001 until 1 July 2011** and is longer than the access arrangement period of five years originally proposed by the service provider. The Commission accepts NT Gas' revised proposal for a longer access arrangement period and considered that in the circumstances of the ABDP a ten-year access arrangement, with the inclusion of a review trigger, was reasonable. The revisions submission date is **1 January 2011**.

As the majority of gas hauled on the ABDP is used in electricity generation, the proposed reference tariff has the potential (in the long term) to affect a range of residential and commercial energy users. The Commission believes that the amendments required in this *Final Decision* ensure fair access and establish an appropriate benchmark for parties involved in future access negotiation on the ABDP.

The Commission has balanced NT Gas' interests with those of potential access seekers. The reference tariff required by the Commission will generate sufficient revenue to cover efficient operating costs, depreciation and a return on investment commensurate with the assumed risks and current market parameters.

This *Final Decision* demonstrates the Code's flexibility to accommodate the specific characteristics of the ABDP. In its access arrangement, NT Gas sought a higher WACC as compensation for the risk that the pipeline might be stranded after 2011. The Commission maintains that the risk of stranding should be managed through accelerated depreciation rather than a premium on the return on equity. This will enable NT Gas to recover most of its capital investment by the end of 2011 and recognises the reasonable expectations of investors, lessees and users as reflected in the Gas Sale Agreement and lease arrangements. The gas transmission pipeline from the production points to the users is leased to and operated by NT Gas as trustee of the Amadeus Gas Trust.

The Commission has now made its *Final Decision* under section 2.16(a)(ii) of the Code not to approve the ABDP access arrangement in its current form. It has identified amendments to the proposed access arrangement that must be satisfactorily incorporated in a revised access arrangement in order for it to be approved (under section 2.19).

NT Gas is required to submit a revised access arrangement to the Commission that complies with this *Final Decision* by **15 January 2003**.

This *Final Decision* provides NT Gas with a benchmark return on equity of 11.67 per cent.

FINAL DECISION AT A GLANCE

Parameter	*NT Gas Proposal* ***(1 July 99 figs)***	*ACCC Final Decision* ***(1 July 2001 figs)***
Access arrangement duration	NT Gas proposed an access arrangement period of ten years, rather than five years. It would commence in July 2001 and end in July 2011	The *Final Decision* accepts a revised access arrangement period from 1 July 2001 to 1 July 2011 with the Revisions Submission Date being 1 January 2011. ▪ The expiration of the lease schedule for the leased pipeline assets provides the key rationale for this access arrangement period. ▪ A trigger has been included to require review of the access arrangement if a new pipeline interconnects with the ABDP or a major new source of gas supplies the ABDP market.
ORC	NT Gas proposed ORC of $318.96m	Following the release of the *Draft Decision* (May 2001) cost changes were identified producing a revised ORC of $373.7m.
DORC	NT Gas proposed DORC of $265m at 1 July 1999.	The Commission accepts that a DORC valuation for the ABDP is likely to be between $304.5m and $373.7m. ▪ The Commission has chosen not to determine a specific DORC as this would involve making an assumption about the likely timing and possible cause of any reduced utilisation of the pipeline beyond 2011. The possible timing and circumstances of such an event remains unclear.
ICB	NT Gas has proposed an initial capital base of $265m at 1 July 1999.	The *Final Decision* assumes an initial capital base of $228.5m as at 1 July 2001.
New Facilities Investment	NT Gas proposed an estimated capital expenditure program for the five-year period, including $2.26m expansion capital to increase the capacity of the Mereenie supply line.	The *Final Decision* concludes that the proposed capital expenditure forecast by NT Gas is likely to meet the criteria in section 8.16 of the Code. However, the Commission will review the capital expenditure in the next access arrangement period against the section 8.16 criteria.

Depreciation allowance	NT Gas proposes to depreciate the leased pipeline assets using accelerated depreciation to \$61.84m in 2011 and standard straight line thereafter until the expiration of the asset's remaining technical life in 2066.	The *Final Decision* accepts NT Gas' arguments about future risks of stranding and proposes a depreciation schedule based on accelerated depreciation for the leased pipeline assets as proposed by NT Gas. This results in a residual value of \$85.9m comprising both the leased and non-leased pipeline assets in 2011.
Rate of return	NT Gas proposed a return on equity between 14.3 and 17.3% per annum.	The *Final Decision* applies the Commission's standard post-tax nominal framework to calculate a post-tax nominal cost of equity of 11.67 per cent.
Non-capital costs	NT Gas aggregated forecasts of non-capital costs and historical costs to arrive at best estimates for this access arrangement period.	The *Final Decision* concludes that the operating, maintenance and other non-capital costs for the ABDP are not unreasonable.
Forecast revenue	NT Gas proposed revenue of \$52.0m for the year ending 30 June 2002. ▪ This corresponded with an aggregated tariff of \$3.46/GJ for the year ending 30 June 2002	The *Final Decision* provided for revenue for the year ending 30 June 2002 of \$45.08m. The key to this difference is the treatment of the ICB. ▪ This corresponds with an aggregated tariff of \$2.88/GJ for the year ending 30 June 2002
Cost allocation and tariff setting	NT Gas proposed a zonal pricing structure. The three zones are between Amadeus Basin, Warrego, Mataranka and Darwin.	The *Final Decision* accepts zonal pricing as an appropriate methodology for determining tariffs.
Incentive structure	NT Gas proposed a rebatable service in the form of its interruptible service.	NT Gas must adjust its incentive structure policy to avoid potentially misleading third parties as to its operation.
Fixed principle	NT Gas proposed one Fixed Principle relating to the roll-in of new facilities investment at the commencement of the next access arrangement period.	The *Final Decision* rejects the Fixed Principle.
Back haul tariffs	NT Gas proposed only a forward haul service.	Despite a number of requests for the inclusion of a back haul tariff, the *Final Decision* does not require one. It is difficult to determine whether or not the demand for a back haul service satisfies section 3.3 of the Code. If required the back haul service could be provided via the negotiated service or be required as result of the activation of the access arrangement trigger mechanism.
Queuing Policy	NT Gas proposed in the fourth dot point of clause 6.4 of the access arrangement, that an existing user with a contractual right in force as at 25 June 1999 would have pre-emptive rights over capacity reservation.	The *Final Decision* accepts NT Gas' queuing policy, but notes that anti-competitive abuse of this clause may breach the access hindering provisions of the Gas Pipelines Access Law.
Extensions / Expansions Policy		The *Final Decision* requires NT Gas to amend its proposed extensions and expansions policy to require it to obtain the Commission's consent before electing to omit expansions from the covered pipeline.

Key Issues

Significance of the Final Decision

NT Gas does not anticipate that revenue will be generated by the sale of the Reference Service or negotiated service during the access arrangement period as the firm capacity of the ABDP is currently fully committed to users under pre-existing transportation contracts. As a consequence, this *Final Decision* is likely to have limited immediate impact for existing users.

However, the *Final Decision* will be an important reference point for future negotiations on gas haulage services in the NT especially in the face of uncertainty concerning delivery of Timor Sea gas to Darwin.

NT Gas proposed a reference tariff of $3.46 for the first year (2001/02)[1] of its access arrangement. The Commission believes this is unreasonably high, and requires a tariff of $2.88/GJ. This will provide sufficient revenue to cover the forecast efficient costs (including capital costs) of running the pipeline. The main reason for the difference is the treatment of depreciation since 1986, with the Commission establishing a lower initial capital base than that proposed by NT Gas.

Initial capital base

NT Gas depreciated its ORC on a straight-line basis over the economic life of the ABDP assets to establish a DORC of $265m at 1 July 1999. More specifically, pipeline assets, which constitute a significant portion of the ABDP's ORC valuation, were depreciated based on an 80-year life.

The Commission considers that the DORC valuation, as calculated by NT Gas, does not provide an appropriate valuation of the ABDP's pipeline assets. It is the Commission's view that the risk of stranding currently faced on the pipeline was evident during the construction of the pipeline and is reflected in the existing lease and contractual arrangements. It is therefore difficult to accept that NT Gas, as a prudent investor, did not recognise the likelihood of stranding earlier and structure its tariffs accordingly.

- In particular, NT Gas has submitted in its access arrangement information that the residual value of the leased pipeline assets on 1 July 2011 will be $61.84m. On the basis of evidence provided, the Commission is satisfied that $61.84m is an appropriate estimate of the residual value of the leased pipeline assets in 2011. In addition, the Commission has reason to believe that this estimated valuation was in existence in 1986. This view is supported by the uncertainty about the potential gas reserves in the Amadeus Basin.

- NT Gas' major foundation contract is expected to expire in 2011.

[1] Given that the access arrangement period will be for ten years the Commission has determined revenues and tariff for the ten-year period commencing 1 July 2001.

The Commission calculated its DORC for this *Final Decision* and concluded, in assessing the likelihood of a reduced economic life of the ABDP compared to its technical life, a range of values represented the possible DORC outcomes. The Commission recognises that when the economic life of an asset is less than its technical life, then DORC tends towards ORC, this produced a valuation of $373.7m, however should the life of the ABDP be extended and the technical and commercial lives were equal then the DORC valuation would be $304.5m.

Given the possibility of a reduced economic life after 2011 the Commission has determined that an Optimised Deprival based valuation provides a meaningful asset valuation. The Commission has determined revenues for the ten-year period commencing 1 July 2001. The Commission has calculated an initial capital base at 1 July 2001 of $228.5m for the ABDP.

Depreciation allowance

The treatment of on-going depreciation has a significant influence on the revenue stream. NT Gas proposed accelerated depreciation of the initial capital base to reflect its concern about the sustainability of current levels of throughput over the life of the pipeline. It argued that there is significant uncertainty given the expiration of its foundation gas transportation contract in 2011, the lack of information on future production capacity of the Amadeus Basin and the potential for Timor Sea gas to enter the Northern Territory.

The *Final Decision* accepts these arguments and that the leased pipeline assets be depreciated to a residual value of $61.84m in 2011. Those assets will then be depreciated on a standard straight-line basis over its remaining economic life (to 2066).

Rate of return

In March 2001 National Economics Research Associates (NERA) released a paper comparing returns of regulated utilities between North America, the United Kingdom and Australia. [2] The key outcome of the study was that returns given by Australian regulators are broadly consistent with returns in North America, which are higher than those in the United Kingdom.

As outlined in its *Draft Regulatory Principles*, the *Post-tax Revenue Model Handbook* and in recent decisions, the Commission prefers to use a post-tax regulatory framework. The post-tax nominal return on equity is better understood by financial markets than the pre-tax real weighted average cost of capital (WACC), with shareholder returns typically being expressed in nominal, post-tax terms.

The *Final Decision* provides NT Gas with a benchmark return on equity of 11.67 per cent. Under the Code, NT Gas could achieve a return on equity in excess of this through lower than forecast operations and maintenance costs and the sale of non-reference services.

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2 International comparison of utilities' regulated post-tax rates of return in: North America; the UK; and Australia. A report prepared by National Economic Research Associates, March 2001.

Table 3: WACC estimates

	per cent	
	NT Gas proposal	**Commission Final Decision**
Nominal cost of equity	14.3-17.3	11.67
Nominal pre-tax cost of debt (r_d)	6.7-7.4	7.07
Nominal vanilla WACC	n/a	8.91
Post-tax nominal WACC	6.5-10.9	7.51
Pre-tax nominal WACC	10.2-17.0	9.09[(b)]
Pre-tax real WACC	8.5-11.7[(a)]	6.75[(b)]

Source: Access arrangement information, p. 26 and Commission analysis.
Note: (a) calculated by NT Gas using the forward transformation formula: $W_{tr} = (1+W_t)/(1+f)-1$
(b) obtained from the Commission's cash flow analysis.

Non-capital costs

NT Gas aggregated forecasts of non-capital costs and historical costs to arrive at best estimates for this access arrangement period. The Commission does not consider NT Gas' operating, maintenance and other non-capital costs for the ABDP to be unreasonable following comparison with other transmission pipelines against a number of key performance indicators.

Forecast revenue

NT Gas applied a cost of service framework to determine total revenue. As a result of the Commission's amendments the forecast regulated revenue for the ABDP will be different to that proposed by NT Gas. The forecast revenue determined by NT Gas and in the *Final Decision* are set out in Table 4.

Table 4: Comparison of forecast revenue, 2002 to 2011

	Forecast revenue (nominal $m)	
Year ending 30 June	**NT Gas**	**ACCC**
2002	53.3	45.08
2003	52.9	45.35
2004	52.8	46.81
2005	53.7	47.12
2006	52.1	47.42
2007	-	47.73
2008	-	35.55
2009	-	35.78
2010	-	36.01
2011	-	36.24

As the pipeline is fully contracted until 2011, it is unlikely that reference services will be sold in this access arrangement period. However, the forecast revenues resulting from the parameters proposed by the Commission would provide the service provider with the opportunity, if it were supplying the reference service, to earn a stream of revenue that would recover efficient costs associated with that service.

Cost allocation and tariff setting

NT Gas proposed to allocate total revenue across three pricing zones. While considered an improvement on postage stamp pricing, zonal tariffs still have the potential to create inefficient pricing signals. As noted in submissions, users located in zone three will be charged the same tariff regardless of whether they are in Katherine or Darwin.

The Commission is of the view that distance based tariffs are likely to provide better price signals to the market than 'postage stamp' or zonal tariffs. However, given that most customers are located at the end of the ABDP, the Commission considers that any loss in efficiency due to zonal pricing would be minimal.

Tariff path and incentive structure

Under the Commission proposed tariff path, for the year ending 30 June 2002, a customer in Zone Three would pay $2.88/GJ. This represents a reduction of approximately 17 per cent when compared to NT Gas' proposal of $3.46/GJ.

The *Final Decision* proposes that NT Gas' tariff smoothing mechanism be amended. When determining the tariff path for the access arrangement period, the Commission prefers the use of a CPI-X approach. This approach, unlike NT Gas', explicitly provides for the effect on tariffs due to actual changes in the CPI and removes the inflation risk inherent in NT Gas' approach.

NT Gas proposed to introduce a rebate mechanism to share revenue from interruptible services according to the requirements of the Amadeus Gas Trust. The *Final Decision* requires amendments to wording of the incentive mechanism to avoid potentially misleading users as to it operation.

Back haul tariffs / trigger review

Given the potential of Timor Sea gas coming onshore, several interested parties sought the inclusion of a back haul tariff. The Commission could require inclusion of back haul reference services if section 3.3 of the Code is satisfied. The Commission at this stage does not consider that back haul services satisfy section 3.3 of the Code. The Commission has not required a back haul tariff.

However, the Commission has required the inclusion of trigger mechanism that would require a review of the access arrangement if a pipeline were to interconnect with the ABDP or a significant new source of gas were to supply a market that the ABDP is supplying. It is the Commission's view that the interest of users and prospective users are taken into account through the inclusion of this trigger mechanism.

Terms and Conditions

Prudential Requirements

NT Gas proposed that users and prospective users must meet prudential requirements prior to the user requesting a service or being placed in a queue.

The *Draft Decision* proposed an amendment to require NT Gas to set out in the access arrangement the prudential requirements that will apply to users and prospective users. NT Gas has provided the Commission with its criteria, and an amendment in this *Final Decision* requires their inclusion in the access arrangement.

Queuing Policy

NT Gas proposed in clause 6.4 of the access arrangement, that an existing user with a contractual right in force as at 25 June 1999 will, have pre-emptive rights over capacity reservation where there is no Service Agreement in place.

The Commission has examined the pre-existing contracts and has been unable at this stage to identify any provisions, which would be defined as an exclusivity right.

The Commission has accepted NT Gas' proposed queuing policy, noting that any misuse of the existing contract clause could be in breach of the Gas Pipelines Access Law and other legislation.

Extensions and expansions policy

The Commission is not satisfied that the extensions and expansions policy as it currently stands, is consistent with the principles set out in section 2.24 of the Code.

The *Final Decision* requires NT Gas to amend its proposed extensions and expansions policy to require it to obtain the Commission's consent before electing to omit expansions from the covered pipeline.

Final decision Amendments

Pursuant to section 2.16(a)(ii) of the Code, the Commission does not approve in its present form NT Gas' proposed access arrangement for the ABDP.

Pursuant to section 2.16(a)(ii) of the Code , the Commission requires NT Gas to resubmit a revised access arrangement by 15 January 2003.

The amendments (or as appropriate, the nature of amendments) that would have to be made in order for the Commission to approve the proposed access arrangements are recorded in this *Final Decision*.

This document sets out the Commission's *Final Decision* on the access arrangement. It does not address those provisions of the original access arrangement that have since been superseded or withdrawn.

The Commission requires NT Gas to make the following amendments to the access arrangement.

Final Decision amendments

Amendment FDA2.1

In order for NT Gas' access arrangement for the ABDP to be approved, the value of the initial capital base must be adjusted to the value derived by the Commission of **$228.5m** as at 1 July 2001.

Amendment FDA3.1

In order for NT Gas' access arrangement for the ABDP to be approved, clause 4 of section 4 of the access arrangement must state that new facilities investment that does not satisfy the requirements of the Code may be undertaken by NT Gas. However, only that portion of the investment that satisfies the requirements of the Code may be included in the capital base.

In order for NT Gas' access arrangement for the ABDP to be approved, clause 6 of section 4 of the access arrangement must be amended to clearly specify that any new facilities investment must meet the requirements of the Code before it can be included in the capital base.

Amendment FDA3.2

In order for NT Gas' access arrangement for the ABDP to be approved, the reference tariff policy must be amended to allow the Commission at the commencement of the subsequent access arrangement period to review, and if necessary adjust, the asset base for wholly or partially redundant assets within the meaning of the Code.

Amendment FDA3.3

In order for NT Gas' access arrangement for the ABDP to be approved, NT Gas should adopt the depreciation schedule given in Table 3.2.

Amendment FDA3.4

In order for NT Gas' access arrangement for the ABDP to be approved, for the purpose of calculating NT Gas' return on capital assets, the working capital component must not be included in the capital base.

Amendment FDA3.5

In order for NT Gas' access arrangement for the ABDP to be approved:

- the WACC estimates and associated parameters forming part of the access arrangement and access arrangement information must be amended to reflect the current financial market settings by adopting the parameters set out by the Commission in Table 3.5 and Table 3.6; and

- the target revenues and forecast revenues must be based on these new parameters.

Amendment FDA3.6

In order for NT Gas' access arrangement to be approved, allowances for the additional tariff component (as detailed in Table D.1 of Confidential Annexure D) must be included in the calculation of forecast revenues.

Amendment FDA3.7

In order for NT Gas' access arrangement for the ABDP to be approved, the ORC valuations for each zone used for the calculation of tariffs should be amended as follows:

Zone One	$171.6m
Zone Two	$118.6m
Zone Three	$83.5m

Amendment FDA3.8

In order for NT Gas' access arrangement for the ABDP to be approved, NT Gas must amend the reference tariff proposed in Section 3 of the access arrangement. The amendment must have the effect that:

- the initial tariff (in 2001/02) is derived from the cost of service revenue resulting from the amendments proposed by the Commission in this *Final Decision*; and
- in each subsequent year, with the exception of the 2007/2008 financial year, the reference tariffs will be calculated using the CPI-X tariff escalator:

$$t_n = t_{n-1} (1 + (CPI_n - CPI_{n-1})/CPI_{n-1}).(1 - X)$$

where X = 1.51 per cent

- In the 2007/2008 financial year a once off tariff adjustment will occur and the tariff will be derived in accordance with the following formula:

$$t_n = t_{n-1} (1 + (CPI_n - CPI_{n-1})/CPI_{n-1}).(1 - X).Y$$

where Y = 0.74
X = 1.51 per cent

Section 3 of the access arrangement must be amended to remove the reference to CPI adjustment of NT Gas' proposed reference tariff for the year to 30 June 2004. In the event that there is a gap between the reference tariff years specified in the access arrangement and the revisions commencement date, the interim reference tariff will be determined by adjusting the final year's reference tariff in accordance with the CPI-X tariff escalator discussed in point two of this amendment.

Amendment FDA3.9

In order for NT Gas' access arrangement for the ABDP to be approved, the following statement must be deleted from Clause 9 of the reference tariff policy:

> 'and to provide other Users of the Pipeline with a share in gains from additional sales of Services.'

Amendment FDA3.10

In order for NT Gas' access arrangement for the ABDP to be approved, the fixed principle (section 4.8) must be deleted.

Amendment FDA4.1

In order for NT Gas' access arrangement for the Amadeus Basin to Darwin Pipeline to be approved, NT Gas must amend the access arrangement to require adoption of a revised gas specification, subject to:

- the enactment of any legislation necessary to facilitate the change in specification;
- recognition and preservation of existing contractual rights and obligations; and

- the specification not precluding continued transportation of gas from existing fields.

Amendment FDA4.2

In order for NT Gas' access arrangement for the Amadeus Basin to Darwin Pipeline to be approved, NT Gas must clearly specify that schedule 2 of the access arrangement prevails over the standard service agreement.

Amendment FDA4.3

In order for NT Gas' access arrangement for the Amadeus Basin to Darwin Pipeline to be approved, NT Gas must include in the access arrangement the prudential requirements set out below:

- the user or prospective user must be resident in, or have a permanent establishment in, Australia.;
- the user or prospective user must not be under external administration as defined in the Corporations Act or under any similar form of administration in any other jurisdiction; and
- the user or prospective user may be required to provide reasonable security in the form of a parent company guarantee or a bank guarantee or similar security. The nature and extent of the security will be determined having regard to the nature and extent of the obligations of the user or prospective user under the Service Agreement.

Amendment FDA4.4

In order for NT Gas's access arrangement for the Amadeus Basin to Darwin Pipeline to be approved, NT Gas must amend section 7.2(b) and insert (c) to its proposed access arrangement to read:

(b) that the expanded capacity will not be treated as part of the pipeline for the purposes of this Access Arrangement and NT Gas will lodge a separate Access Arrangement in respect of that expanded capacity; or

(c) that the expansion will not be covered, subject to the consent of the Commission prior to the expansion coming into service.

Amendment FDA4.5

In order for NT Gas's access arrangement for the Amadeus Basin to Darwin Pipeline to be approved, NT Gas must amend clause 9.2 of the access arrangement:

- to specify 1 January 2011 as the Revisions Submission Date; and
- to include the following trigger mechanism:

  NT Gas is required to submit revisions to this access arrangement within one month of receiving written notification by the Commission that one of the following major events has occurred:

(i) the interconnection of another pipeline with the ABDP; or

(ii) the introduction of a significant new source of gas supply to one of the ABDP's markets;

that substantially changes the types of Services that are likely to be sought by the market or has a substantial effect on the direction of the flow of natural gas through all or part of the pipeline.

Amendment FDA5.1

For the access arrangement to be approved, the Commission requires NT Gas to revise its access arrangement information so that it is consistent with the most recent information provided to the Commission as part of the completion of the *Final Decision*, and incorporate relevant amendments specified in this *Final Decision*.

1. Introduction

On 25 June 1999 NT Gas Pty Limited submitted a proposed access arrangement and access arrangement information for the Amadeus Basin to Darwin Pipeline (ABDP) to the Australian Competition and Consumer Commission (‘the Commission’), for approval under the *National Third Party Access Code for Natural Gas Pipeline Systems* (the Code).

The access arrangement and access arrangement information describe the terms and conditions on which the company will make access to its pipeline available to third parties. The Commission has assessed the access arrangement and access arrangement information against the principles in the Code based on information provided by AGL Pipelines (NSW) Pty Limited (AGLP) and other interested parties.

This document sets out the Commission’s *Final Decision* and required amendments under section 2.16(a) of the Code for NT Gas’ access arrangement.

This introduction includes:

- a description of the regulatory framework;
- a description of the Northern Territory (NT) gas industry structure;
- an outline of the ABDP access arrangement submitted for approval;
- a summary of the criteria for assessing an access arrangement under the Code;
- a summary of the consultative process undertaken as part of the Commission’s assessment; and
- the Commission’s *Final Decision*, and an outline of the path to the Commission’s *Final Approval*.

Chapter 2 of this *Final Decision* considers the initial capital base.

Chapter 3 determines the regulated rate of return and reference tariffs for third party access. The reference tariff principles in section 8 of the Code are examined.

Chapter 4 provides an assessment of the access arrangements of the non-tariff mandatory elements in the Code.

Chapter 5 examines information provisions and performance indicators.

Chapter 6 sets out the Commission’s *Final Decision*. The Commission has identified amendments that would need to be made to the access arrangement in order for it to be approved. These proposed amendments are set out in the relevant sections of the *Final Decision* and are brought together in the Executive Summary.

1.1 Regulatory framework

The main legislation and relevant documents regulating access to the NT gas transmission industry are:

- the Code, under which transmission service providers are required to submit access arrangements to the Commission for approval;
- the *Gas Pipelines Access (South Australia) Act 1997*;[3] and
- the *Gas Pipelines Access (NT) Act 1998*.

Code Bodies and Appeals Bodies in NT with respect to transmission pipelines are:

- the Commission – Regulator and Arbitrator;[4]
- the National Competition Council – Code Advisory Body;
- the Commonwealth Minister – Coverage Decision Maker;
- the Federal Court – judicial review; and
- the Australian Competition Tribunal – administrative appeal.

The Commission is currently the relevant regulator with respect to gas transmission and distribution pipelines in the Northern Territory.

Section 2 of the Code specifies that the service provider is required to submit a proposed access arrangement (and associated access arrangement information) to the regulator for approval. The service provider is defined as 'a person who owns (whether legally or equitably) or operates the whole or any part of a Pipeline'. Ownership of the ABDP is vested in a consortium of banks.

1.2 The NT gas industry structure

1.2.1 Structure of the gas industry in the Northern Territory

Natural gas was first discovered at the Amadeus Basin, near Alice Springs, in both the Palm Valley and Mereenie fields during the mid 1960s. These discoveries, while significant, remained undeveloped due to the inaccessibility of markets for such remote reserves. In September 1983 gas for base load electricity generation was first produced

[3] South Australia acted as 'lead legislator' for the national gas access legislation.

[4] The Commission is also Regulator and Arbitrator with respect of transmission pipelines in the other States and Territories with the exception of Western Australia.

and delivered to the Power and Water Corporation (PWC)[5] at Alice Springs, 150kms from the Palm Valley gas field.[6]

In 1984 the NT Government began construction of a new coal fired power station on Channel Island some 42kms from the city of Darwin. During the course of constructing the power station, the NT Government, after conducting a feasibility study of the gas reserves in the Amadeus Basin and assessing the economics of hauling natural gas to Darwin via pipeline, committed both the Channel Island and Katherine power stations to be fuelled by natural gas. The 1985 Gas Sales Agreement (GSA)[7] between NT Gas and the Northern Territory Electricity Commission (now PAWA) formed the cornerstone of the ABDP and facilitated its initial construction.

NT Gas was formed from a consortium of companies to finance, construct, commission and operate the ABDP. The pipeline was commissioned in December 1986 and the first gas delivered to PAWA in January 1987.

The gas transmission pipeline from the production points to the users is leased to and operated by NT Gas as trustee of the Amadeus Gas Trust. In 1988 the AGL Group acquired through wholly owned subsidiaries[8] 96 percent of NT Gas, the other shareholders being Darnor Pty Limited (an NT Government company) (2.5 percent) and Centrecorp Aboriginal Investment Corporation Pty. Limited (a company owned by the Central Land Council) (1.5 percent). The subsidiary pipelines that service larger users are operated by NT Gas in association with other companies. Envestra and NT Gas operate the transmission pipeline from Palm Valley to Alice Springs and the PWC along with NT Gas operate the Macarthur River pipeline that services the large Macarthur River mine.

Since the commissioning of the ABDP a number of lateral pipelines have been constructed to interconnect into the ABDP (none of which form part of the ABDP for the purposes of this access arrangement) including the:

- McArthur River pipeline which was commissioned in February 1995. The gas was supplied to fuel the power station at the McArthur River mine. This pipeline, however, is currently not operating in its intended mode in that its operating pressure is restricted.

- Darwin City Gate to Berrimah pipeline. This was commissioned in January 1996 and gas was supplied to industrial users in Darwin in January 1996.

Mt Todd pipeline which was commissioned in October 1996. The gas was supplied to fuel the power station at the Mt Todd mine. In November 1997 mining operations were suspended at the mine after the mine’s owner Pegasus Gold Australia Pty Limited became insolvent, forcing the recently commissioned pipeline infrastructure out of

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5 Then known as the Northern Territory Electricity Commission.

6 Gas is delivered to Alice Springs through the Palm Valley to Alice Springs Pipeline which was recently sold by Holyman Limited to Envestra Limited.

7 This document is confidential

8 Agex Pty Limited and Sopic Pty Limited.

service. The mining operation has recommenced operation, but with lower demand for electricity than previously.

There are two gas producers in the NT that access gas from the Amadeus Basin. Magellan operates the field at Palm Valley, and Santos operates the Mereenie field. The total amount of gas produced by these basins was 18.3 PJ in 1999.

The gas produced in the NT is largely used for electricity generation. With respect to the 1999 production figures 13.6 PJ was used in electricity generation at Channel Island, Katherine and other power stations along the pipeline. Approximately 0.15 PJ goes to reticulation in urban areas such as Alice Springs, Katherine and other smaller towns along the pipeline. The remaining 4.5 PJ being used by major users such as the mines at Macarthur River and smaller industrial users in the Mataranka industrial region outside Darwin. Origin retails in Alice Springs and NT Gas Distribution retails in Darwin.

Current throughput of the ABDP is around 16 PJ per annum, with some 99.7 percent of total pipeline throughput being delivered to power generation facilities situated at various locations along the pipeline. Those facilities are either owned by PWC or delivered to other such facilities on behalf of PWC. The remaining pipeline throughput is to service small industrial customers in Darwin and industrial use at Mataranka.

There is currently no available firm capacity on the ABDP, with all existing capacity being utilised under existing agreements. There is in the vicinity of 5TJ per day of capacity available on an interruptible basis – the availability of such capacity depends on seasonal factors, reflecting that gas transported through the ABDP is primarily used for power generation.[9]

The location of the ABDP is illustrated in Figure 1.

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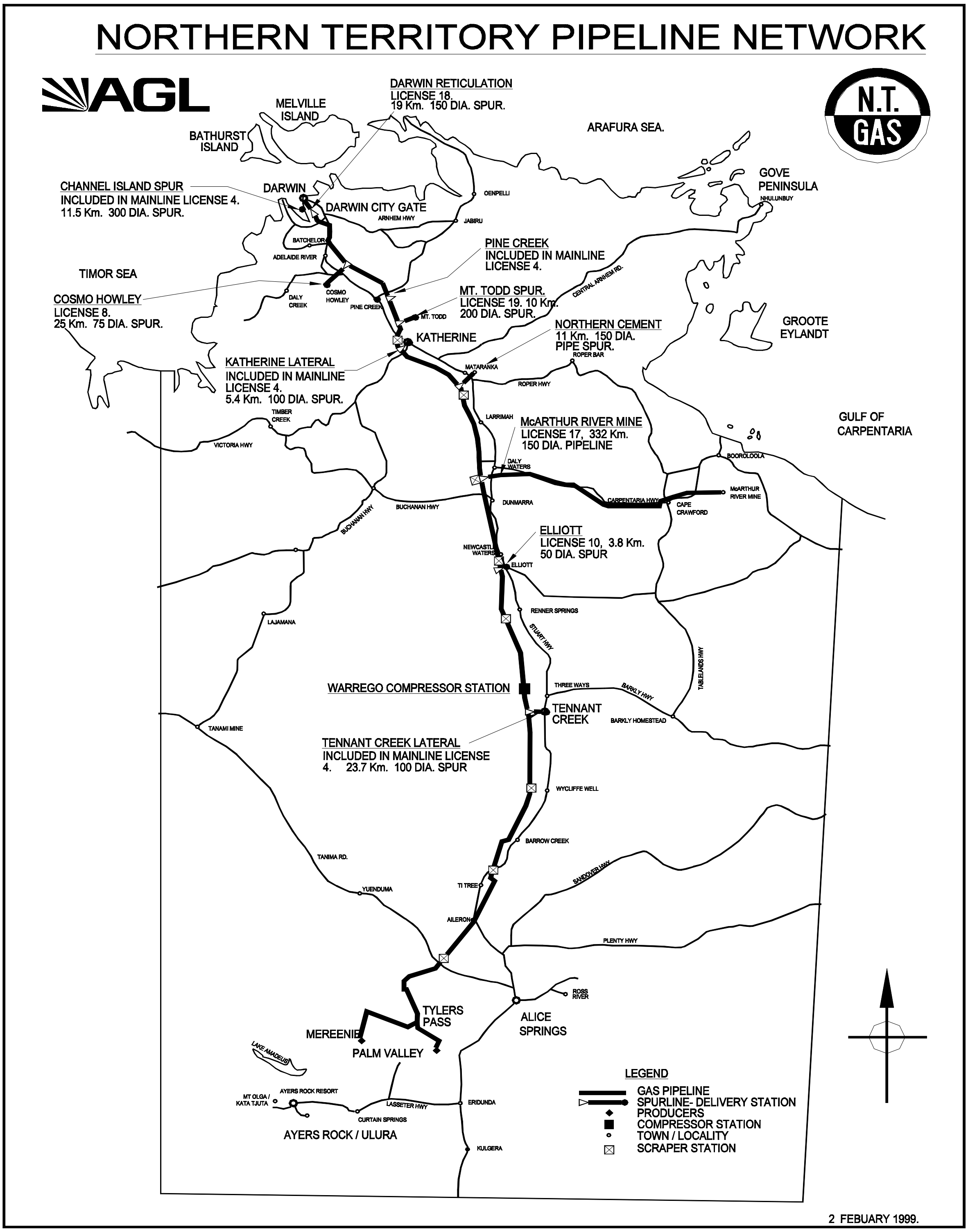
[9] Approximately 99 percent of gas sold in the NT is used for the generation of electricity, and approximately 84 percent of electricity consumed in the Territory is generated from gas (see ACCC Draft Decision on the Mereenie Gas Sales Agreement).

Figure 1.1: Map of Amadeus Basin to Darwin Pipeline



Source: Access Arrangement Information, p. 53.

1.3 Criteria for assessing an access arrangement

The Commission may approve an access arrangement only if it is satisfied that it contains the elements and satisfies the principles set out in sections 3.1 to 3.20 of the Code, which are summarised below. An access arrangement cannot be rejected by a regulator solely on the basis that it does not address a matter that section 3 of the Code does not require it to address. Subject to this, the Commission has a broad discretion in accepting or opposing an access arrangement.

An access arrangement must include a policy on the service or services to be offered which includes a description of the service(s) to be offered. The policy must include one or more services that are likely to be sought by a significant part of the market and any service(s) that in the Commission’s opinion should be included in the policy. To the extent practicable and reasonable, users and prospective users must be able to obtain those portions of the service(s) that they require, and the policy must also allow for a separate tariff for an element of a service if requested.

An access arrangement must also contain one or more reference tariffs. A reference tariff operates as a benchmark tariff for a particular service and provides users with a right of access to the service at the reference tariff. Tariffs must be determined according to the reference tariff principles in section 8 of the Code.

An access arrangement must include the following elements:

- **services policy** which must include a description of one or more services that the service provider will offer to users and prospective users;

- **reference tariffs and reference tariff policy**, including one or more reference tariffs. Tariffs must be determined according to the reference tariff principles in section 8 of the Code;

- **terms and conditions** on which the service provider will supply each reference service;

- a statement that the covered pipeline is either a contract carriage or market carriage pipeline (**capacity management policy**);

- a **trading policy** that enables a user to trade its right to obtain a service (on a contract carriage pipeline) to another person;

- a **queuing policy** to determine users' priorities in obtaining access to spare and developable capacity on a pipeline;

- an **extensions/expansions policy** to determine the treatment of an extension or expansion of a pipeline under the Code;

- a date by which revisions to the access arrangement must be submitted; and

- a date by which the revisions are intended to commence.

In considering whether an access arrangement complies with the Code, the Commission must take into account, pursuant to section 2.24 of the Code the following factors:

(a) the Service Provider's legitimate business interests and investment in the Covered Pipeline;

(b) firm and binding contractual obligations of the Service Provider or other persons (or both) already using the Covered Pipeline;

(c) the operational and technical requirements necessary for the safe and reliable operation of the Covered Pipeline;

(d) the economically efficient operation of the Covered Pipeline;

(e) the public interest, including the public interest in having competition in markets (whether or not in Australia);

(f) the interests of Users and Prospective Users;[10]

(g) any other matters that the Relevant Regulator considers are relevant.

On 23 August 2002 the Full Court of the Supreme Court of Western Australia handed down its decision in the matter of: Re Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231 (the Epic decision). This decision is the most authoritative assessment available of the interpretation of the Code and its supporting legislation. Accordingly, in reaching its *Final Decision*, the Commission has considered carefully the implications of the Epic decision.

The Epic decision largely focused on the appropriate approach to adopt when setting the initial capital base for a pipeline and provides valuable guidance in interpretation that is directly relevant to the current review. In particular, the Court found that the factors in section 2.24 of the Code are relevant to the whole of an access arrangement, including reference tariffs and the reference tariff policy. In determining reference tariffs and the reference tariff policy, the regulator should apply the objectives in section 8.1, but should be guided by section 2.24 where these objectives conflict or give the regulator discretion. A regulator must consider each of the factors specified in section 2.24 as fundamental elements.

1.4 The Commission's assessment process

The proposed access arrangement and access arrangement information describe the terms and conditions on which NT Gas will make access to the ABDP available to third parties during the initial access arrangement period, which NT Gas proposed to last until mid-2011. However, under the provisions of the Code, NT Gas has the discretion to submit revisions earlier than the scheduled review.

The Commission's assessment process relates to the initial access arrangement period.

Section 2 of the Code sets out the assessment process to be undertaken. The Commission is required to:

- inform interested parties that it has received the access arrangement from NT Gas;
- publish a notice in a national daily paper which at least describes the covered pipeline to which the access arrangement relates; state how copies of the documents may be obtained and request submissions by a date specified in the notice;

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10 'User' means a person who has a current contract for a service or an entitlement to a service as a result of an arbitration (section 10.8 of the Code).

- after considering submissions received, issue a *Draft Decision* which either proposes to approve the access arrangement or not to approve the access arrangement and states the amendments (or nature of the amendments) which must be made to the access arrangement in order for the Commission to approve it. Submissions will be sought again following release of the Commission's *Draft Decision*;

- after considering any additional submissions, issue a *Final Decision* stating that it either approves or does not approve the access arrangement (or revised access arrangement) and the amendments (or nature of the amendments) that must be made to the access arrangement (or revised access arrangement) in order for the Commission to approve it; and

- if the amendments are satisfactorily incorporated in a revised access arrangement; issue a *Final Approval*. If not, the Commission must draft and approve its own access arrangement.

1.4.1 Basis of assessment

The Commission considers that the leasing arrangement for the ABDP raises questions about how the pipeline should be assessed. The Commission accepts NT Gas' proposed approach that the Commission's assessment of the pipeline should be conducted under the assumption that NT Gas is the owner of the pipeline. The Commission considers that if the pipeline were assessed on the basis of the leasing arrangements alone, then regulated returns might not be consistent with the underlying investment decision.

1.4.2 The Commission's assessment process to date

Pursuant to the requirements of the Code, in August 1999 the Commission published a notice in a national newspaper and informed interested parties that it had received NT Gas' transmission access arrangement, and invited, received and considered submissions from interested parties.

In order to help foster the consultative process, the Commission released an *Issues Paper* in August 1999.

The Commission received written submissions from five interested parties regarding the proposed access arrangement (see Annexure A).

The major issues raised by interested parties in the submission included:

- valuation of the initial capital base;

- rate of return;

- depreciation;

- reference tariffs;

- terms and conditions, such as the gas specification; and

- other non-tariff elements such as the services policy, queuing policy and term and review policy.

Following receipt of NT Gas' access arrangement and access arrangement information on 25 June 1999, the Commission assessed the access arrangement information for compliance with the requirements of 2.6 and 2.7 of the Code. Pursuant to section 2.9(a) of the Code, the Commission determined that the access arrangement information did not satisfy those requirements, and decided to seek further information from NT Gas.

On 20 August 1999, the Commission issued a notice under section 41 of the Gas Pipelines Access Law on NT Gas for required information. This information included: the existing transportation contracts for the ABDP; a copy of the independent auditors' report of the asset valuation and electronic copy of all financial models used in developing the access arrangement information. In addition to issuing the section 41 notice, the Commission sought from NT Gas information on a number of issues including justification for NT Gas' proposed WACC of 11 per cent and accelerated depreciation of the regulatory asset base.

A further section 41 notice was issued on 11 July 2001 to obtain additional information from NT Gas in order to substantiate cost bases and clarify the lease arrangements.

1.5 Period of the ABDP access arrangement

The Commission accepts NT Gas' proposal for an extended access arrangement period[11] that coincides with the existing lease arrangement. This *Final Decision* provides for an access arrangement period to **1 July 2011** and determines that **1 January 2011** is the Revisions Submission Date.

1.6 *Final Decision*

Final decision

After considering submissions and the revised access arrangement (if submitted by the service provider), the Commission must issue a *Final Decision* (pursuant to section 2.16(a) of the Code) which:

(i). approves the access arrangement; or

(ii). does not approve the access arrangement or revised access arrangement and provides reasons why it does not approve the (revised) access arrangement and states the amendments (or nature of the amendments) which would have to be made to the (revised) access arrangement in order for the Commission to approve it and the date by which a revised access arrangement must be submitted; or

(iii). approves a revised access arrangement.

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[11] Letter from Agility Management, on behalf of NT Gas, to Commission staff 17 April 2002.

The Commission has now made its *Final Decision* under section 2.16(a)(ii) of the Code not to approve the ABDP access arrangement in its current form. It has identified amendments to the proposed access arrangement that must be satisfactorily incorporated in a revised access arrangement in order for it to be approved (under section 2.19). The proposed amendments are set out in the relevant sections in the *Final Decision* and in the Executive Summary.

NT Gas is required to submit a revised access arrangement to the Commission that complies with this *Final Decision* by **15 January 2003**.

If the service provider does not submit a revised access arrangement by the required date, or does so and the Commission is not satisfied that it incorporates amendments specified in the *Final Decision*, the Commission must draft and approve its own access arrangement (section 2.20 of the Code). Such a decision is subject to merits review by the Australian Competition Tribunal under the GPAL.

2. The initial capital base

2.1 Code requirements

The Code requires the Commission to approve a value for an existing pipeline (an initial capital base, ICB) as part of the first access arrangement for that pipeline. This value carries over into subsequent access arrangement periods, subject to deduction of depreciation and redundant capital and addition of new facilities investment.

The principles for establishing the initial capital base of a pipeline system are set out in section 8 of the Code. These principles distinguish between pipeline systems that were in existence at the commencement of the Code (sections 8.10 and 8.11) and those that come into existence after the commencement of the Code (sections 8.12 and 8.13).

The initial capital base – existing pipelines

Section 8.10 of the Code provides that when a reference tariff is first proposed for a reference service the following factors should be considered in establishing the initial capital base for the pipeline:

- the value that would result from taking the actual capital cost of the pipeline and subtracting the accumulated depreciation for those assets charged to users (or thought to have been charged to users) prior to the commencement of the Code (DAC) (section 8.10(a));
- the value that would result from applying the depreciated optimised replacement cost methodology in valuing the pipeline (DORC) (section 8.10(b));
- other well recognised asset valuation methodologies (section 8.10(c));
- the advantages and disadvantages of each valuation methodology applied under paragraphs (a), (b) and (c) (section 8.10(d));
- international best practice and the impact on the international competitiveness of energy consuming industries (section 8.10(e));
- the basis on which tariffs have been (or appear to have been) set in the past, the economic depreciation of the covered pipeline, and the historical returns to the service provider from the covered pipeline (section 8.10(f));
- the reasonable expectations of persons under the regulatory regime that applied to the pipeline prior to the commencement of the Code (section 8.10(g));
- the impact on the economically efficient utilisation of gas resources (section 8.10(h));
- the comparability with the cost structure of new pipelines that may compete with the pipeline in question (for example, a pipeline that may by-pass some or all of the pipeline in question) (section 8.10(i));

- the price paid for any asset recently purchased by the service provider and the circumstances of that purchase (section 8.10(j)); and
- any other matters considered relevant (section 8.10(k)).

For existing pipelines, section 8.11 of the Code states that the value of the initial capital base normally should not fall outside the range of values determined by DAC and DORC.

In addition, the Commission is guided by other factors and objectives for the design of a reference tariff and the reference tariff policy outlined in the Code.

Section 2.24 of the Code states that the regulator may approve a proposed access arrangement only if the regulator is satisfied that the proposed access arrangement contains the elements and satisfies the principles set out in sections 3.1 to 3.20 of the Code. Relevantly, section 3.5 of the Code requires the access arrangement to include a policy describing the principles that are to be used to determine a reference tariff (a reference tariff policy). This reference tariff policy must, in the regulators opinion, comply with the reference tariff principles described section 8 of the Code.

The reference tariff policy and reference tariffs should be designed to achieve a number of objectives that are set out in section 8.1 of the Code:

> (a) providing the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the Reference Service over the expected life of the assets used in delivering that Service;
>
> (b) replicating the outcome of a competitive market;
>
> (c) ensuring the safe and reliable operation of the Pipeline;
>
> (d) not distorting investment decisions in Pipeline transportation systems or in upstream and downstream industries;
>
> (e) efficiency in the level and structure of the Reference Tariff; and
>
> (f) providing an incentive to the Service Provider to reduce costs and to develop the market for Reference and other Services.
>
> To the extent that any of these objectives conflict in their application to a particular Reference Tariff determination, the Relevant Regulator may determine the manner in which they can best be reconciled or which of them should prevail.

In addition, section 8.2 provides that when approving a reference tariff and reference tariff policy the regulator must be satisfied that:

> (a) the revenue to be generated from the sales (or forecast sales) of all Services over the Access Arrangement Period (the Total Revenue) should be established consistently with the principles and according to one of the methodologies contained in this section 8;
>
> (b) to the extent that the Covered Pipeline is used to provide a number of Services, that portion of Total Revenue that a Reference Tariff is designed to recover (which may be based upon forecasts) is calculated consistently with the principles contained in this section 8;
>
> (c) a Reference Tariff (which may be based upon forecasts) is designed so that the portion of Total Revenue to be recovered from a Reference Service (referred to in paragraph (b)) is recovered from the Users of that Reference Service consistently with the principles contained in this section 8;

(d) Incentive Mechanisms are incorporated into the Reference Tariff Policy wherever the Relevant Regulator considers appropriate and such Incentive Mechanisms are consistent with the principles contained in this section 8; and

(e) any forecasts required in setting the Reference Tariff represent best estimates arrived on a reasonable basis.

The reference tariff principles outlined in sections 8.1 and 8.2 are designed to provide flexibility so that reference tariffs and reference tariff policies can be designed to meet the specific needs of each pipeline.

However, section 8.1 includes objectives that may, at times, be in conflict with each other. On these occasions the regulator must determine how the conflict will be reconciled by reference to the factors in section 2.24 of the Code. Section 2.24 states:

…In assessing a proposed Access Arrangement, the Relevant Regulator must take the following into account:

(a) the Service Provider's legitimate business interests and investment in the Covered Pipeline;

(b) firm and binding contractual obligations of the Service Provider or other persons (or both) already using the Covered Pipeline;

(c) the operational and technical requirements necessary for the safe and reliable operation of the Covered Pipeline;

(d) the economically efficient operation of the Covered Pipeline;

(e) the public interest, including the public interest in having competition in markets (whether or not in Australia);

(f) the interests of Users and Prospective Users;

(g) any other matters that the Relevant Regulator considers are relevant.

The recent Western Australian Supreme Court Epic decision provides guidance as to the appropriate application of sections 8.1 and by regulator. The Court stated:

... The last paragraph of s8.1 recognises that the objectives of (a) to (f) in s8.1 may conflict in their application to a particular reference tariff determination, in which event the Regulator may determine the manner in which they can best be reconciled or which of them should prevail. Contrary to the submissions of the Regulator and Alinta, the discretionary task of seeking to reconcile conflicting objectives within s8.1, and even more significantly of determining which of them should prevail, cannot be decided by reference to s8.1 itself. Of necessity, the Regulator must have guidance outside of s8.1 in exercising those discretions. In this regard it appears from the structure and provisions of the Code that have been canvassed that s2.24(a) to (g) would most naturally guide the Regulator in the exercise of these discretions, and was intended to do so. That is, in exercising the discretions contemplated by the last paragraph of s8.1 the Regulator should take into account the factors in s2.24(a) to (g).[12]

[12] Re Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231 at paragraph 85.

2.2 NT Gas' proposal

Consistent with section 8.10 (b) of the Code, NT Gas evaluated the initial capital base using the DORC methodology. NT Gas' reasons for selecting the DORC methodology over alternative asset valuation approaches included:

- the optimisation process allows technological benefits to be passed onto users while the cost of stranded/unutilised assets are not passed on;
- redundant or oversized assets are not included in the asset base, and therefore are not paid for by the users;
- DORC provides a consistent valuation between new and existing assets, regardless of past operating and accounting policies; and
- DORC sends correct price signals as to the cost of providing the service[13].

A number of key assumptions were adopted in the DORC evaluation, including:

- estimates of likely pipeline throughput were prepared for the 30-year period out to 2029 under three scenarios - a base, base reduced and a high case. The base reduced case assumes pipeline throughput peaks in 2015 before reducing by around 50 per cent by 2030, reflecting NT Gas' uncertainty as to future throughput.
- optimised replacement cost of pipeline and associated ancillary equipment assume 'brown-field' conditions given their geographical locations.
- materials and pipe sizes have been optimised to reflect the application of current industry design and construction practice.
- the optimum pipeline configuration is selected on the basis of the lowest NPV of the estimated capital and operating costs over the analysis period.
- depreciation has been applied to the ORC on a 'straight line' basis over the economic life of the assets comprising the ABDP. The economic life assumptions used by NT Gas are given in Table 2.1 below.
- the 'minimum remaining life' philosophy has been applied where NT Gas considers it appropriate.[14]

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13 NT Gas Access Arrangement Information, p.10

14 The 'minimum remaining life' philosophy assumes the asset always has a minimum value until it is replaced or abandoned. For all long lived pipeline assets the minimum remaining life was set at 5 years. All other assets were depreciated to zero over their economic lives.

Table 2.1: Economic lives for the ABDP proposed by NT Gas

Asset	Economic Life (years)	Average Remaining Economic Life at 1 July 1999
Transmission Pipeline (coated and CP protected): Constructed 1986	80	67
Compressor Stations:		
Rotating Equipment	25	22
Station Facilities	35	32
Regulation and Metering Stations	50	37
Odorising Stations	35	22
SCADA	15	2

Source: Access Arrangement Information, p. 20.

Based on the assumptions detailed above, NT Gas calculated an ICB of $265.54m as at 1 July 1999. The results of NT Gas's DORC valuation are summarised in Table 2.1. The ORC valuation listed in the table is the optimum pipeline configuration required to transport the quantities in the base and high case scenarios. NT Gas stated that in light of the uncertainty over both ORC valuations (in that it is a theoretical exercise) and throughput estimates, the replacement cost of the existing pipeline configuration was considered the most appropriate basis upon which to determine the DORC valuation of the ABDP.[15]

15 Access Arrangement Information, p. 11.

Table 2.2: NT Gas' proposed valuation of the initial capital base for the ABDP

Asset type	$ million (at 30 June 1999)[(a)]				
	RC[(b)]	ORC[(c)]	Adjusted ORC [(d)]	Accum. Dep.	DORC
Transmission pipeline	300.31	308.12	300.31	48.81	251.51
Compressor stations:					
Rotating equipment	2.00	6.00	2.00	0.23	1.77
Station facilities	5.00	10.00	5.00	0.41	4.59
Regulation and metering stations	9.78	9.78	9.78	2.48	7.30
Odourisation stations	0.25	0.25	0.25	0.09	0.16
SCADA and communications	1.62	1.62	1.62	1.40	0.22
Total asset value	318.96	335.77[(e)]	318.96	53.42	265.54

Source: Access Arrangement Information, p. 12.

Notes: (a) All cost information in the table is in 1999 dollars.

(b) The replacement cost (RC) of the current configuration.

(c) Pipe sizes optimised to reflect current industry design and construction practice and is the optimum pipeline configuration yielded from analysis based on the base and high case scenarios. Two optimised configurations were considered for the base reduced case throughput scenario, which resulted in a total replacement cost of $313.12m and $326.77m respectively.

(d) ORC has been adjusted to represent the replacement cost of the existing assets.

Consistent with the Code, NT Gas also considered values for the ICB using Depreciated Actual Cost (DAC) (section 8.10(b)) and other commonly prescribed methodologies - residual value (based on economic depreciation) and Optimised Deprival Value (ODV) (section 8.10(c)).

Depreciated Actual Cost (DAC)

NT Gas calculated the DAC of the ABDP to be $234.7m. The methodology adopted by NT Gas to determine the DAC involved subtracting accumulated depreciation of the assets (charged on the basis of what NT Gas considered reasonable) from the total capital cost of the assets. Total capital cost included the actual capital cost of constructing the pipeline plus actual capital expenditure incurred since the pipeline was commissioned.

NT Gas acknowledged the difficulties in determining a DAC valuation for a leased asset where accumulated depreciation for statutory account purposes has not been previously calculated. In calculating the DAC, NT Gas assumed the asset was owned and operated by the same entity to date, depreciating it according to reasonable accounting standards.[16]

[16] Access Arrangement Information, p.12.

Residual Value (based on economic depreciation)

NT Gas undertook an analysis of the historical revenues and returns of the ABDP to determine whether there had been an under or over recovery of revenues. This required an estimation of the economic depreciation that has occurred on the ABDP since it was commissioned. NT Gas applied the following formula in estimating the economic depreciation for each year of operation:

Economic depreciation = revenue – operating costs – return on assets

Where economic depreciation is negative (an under-recovery of capital), this is added to the capital base to be recovered in later years. Where economic depreciation is positive, this is deducted from the capital base. Like the DAC calculation, NT Gas assumed actual capital costs at the time of commissioning and added actual capital expenditure since commissioning to arrive at the total capital cost of the assets. The return on assets was derived by applying a return equivalent to the long term bond rate in each year plus an additional risk premium of two per cent[17] to the capital base.

NT Gas stated that this analysis yields a value for the ABDP in excess of the DORC valuation, and suggested that the DORC methodology is the appropriate methodology for establishing the ICB. NT Gas' analysis also indicated that there was an under-recovery of revenue in every year since the ABDP was commissioned in 1986.[18]

Optimised Deprival Value (ODV)

The ODV methodology establishes the asset valuation as the lesser of the net present value (NPV) of the income that can be generated from the asset, and DORC. The ODV for the ABDP was calculated using the current income stream determined from existing contracts over a 30-year period, a residual value calculated under the 'perpetual method'[19] and a pre-tax real discount rate of 11 per cent. According to NT Gas' calculations, this provides an NPV valuation for the pipeline of $308.9m. NT Gas state that because this value is higher than the DORC asset valuation, the ODV valuation for the ABDP would be DORC.

Depreciation

As stated earlier, NT Gas applied depreciation to its ORC on a 'straight line' basis over the economic life of the assets comprising the ABDP to establish a DORC of $265.5m.[20] Specifically, pipeline assets were depreciated based on an 80-year life.

To recognise the risk of stranding faced by the ABDP, NT Gas then proposed to depreciate the leased pipeline assets using accelerated depreciation to a residual value

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17 Agility letter to ACCC, 7 December 2000.

18 Access Arrangement Information, p.15.

19 The perpetual method calculates a residual by taking the each year's earnings before depreciation and dividing it by the discount rate.

20 Access Arrangement Information, p. 11.

of $61.84m at 1 July 2011 and standard straight line depreciation thereafter until the end of the assets technical life in 2066.[21]

2.3 Commission's *Draft Decision*

2.3.1 Connell Wagner report

The Commission commissioned Connell Wagner Pty Ltd (Connell Wagner) to undertake a desktop audit of NT Gas' DORC valuation for the ABDP.

Optimised Replacement Cost

Connell Wagner conducted its assessment using NT Gas' base case reduced throughput scenario (outlined above). Connell Wagner made the following key findings in its review of NT Gas' ORC valuation:[22]

- NT Gas' proposed pipeline system design configurations did not represent the entire suite of pipeline configurations.
- Unit costs for the pipeline should be $15,200 to $19,500 per inch per kilometre over the length of the ABDP.
- NT Gas assumed higher unit costs than Connell Wagner for the ABDP laterals.
- NT Gas did not assume any cost difference for the installation of a second unit at a compressor station and recommended that the cost of second (and subsequent units) should be calculated at 66 per cent of the installation cost of the first unit.
- The cost for meter stations was estimated by Connell Wagner to be $5m compared to AGL/NT Gas' valuation of $9.78m.
- Provision for establishing maintenance support services for pipeline operations was not included in NT Gas' ORC estimate.
- NT Gas did not make sufficient allowances for native title compensation and interest during construction.
- Based on available information Connell Wagner was not able to confirm AGL's stated ±10 per cent cost estimating accuracy. It was Connell Wagner's view that the level of disaggregation proposed by NT Gas was likely to provide a cost estimate accuracy of ±25 per cent at best.
- Connell Wagner considered an assessment term of 15 years (compared to NT Gas' 30 year term) more reasonable for flow forecasts and the NPV analysis of pipeline system costs.

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[21] Access Arrangement Information, p. 18.

[22] Connell Wagner Pty Ltd, 'Review of NT Gas' DORC Valuation for the Amadeus Basin to Darwin Pipeline' *Draft Report*, May 2000.

Connell Wagner estimated an ORC of $308m, around 3 per cent lower than NT Gas' existing system ORC of $319m. Without further information and more detailed assessment of the ABDP, the order of accuracy of Connell Wagner's estimates was within the range of -5 to +15 per cent, with 75 per cent confidence.

Depreciated Optimised Replacement Cost

Connell Wagner questioned NT Gas' approach to depreciating ORC. Connell Wagner disagreed with NT Gas' approach to using a technical life of 80 years to derive its proposed DORC from ORC and then applying accelerated depreciation based on a residual value of $61.84m in 2011. Connell Wagner put forward four possible scenarios for depreciating the ORC value to arrive at the DORC. The four scenarios were described as follows:

Scenario 1 – standard straight-line depreciation over the technical life of the pipeline;

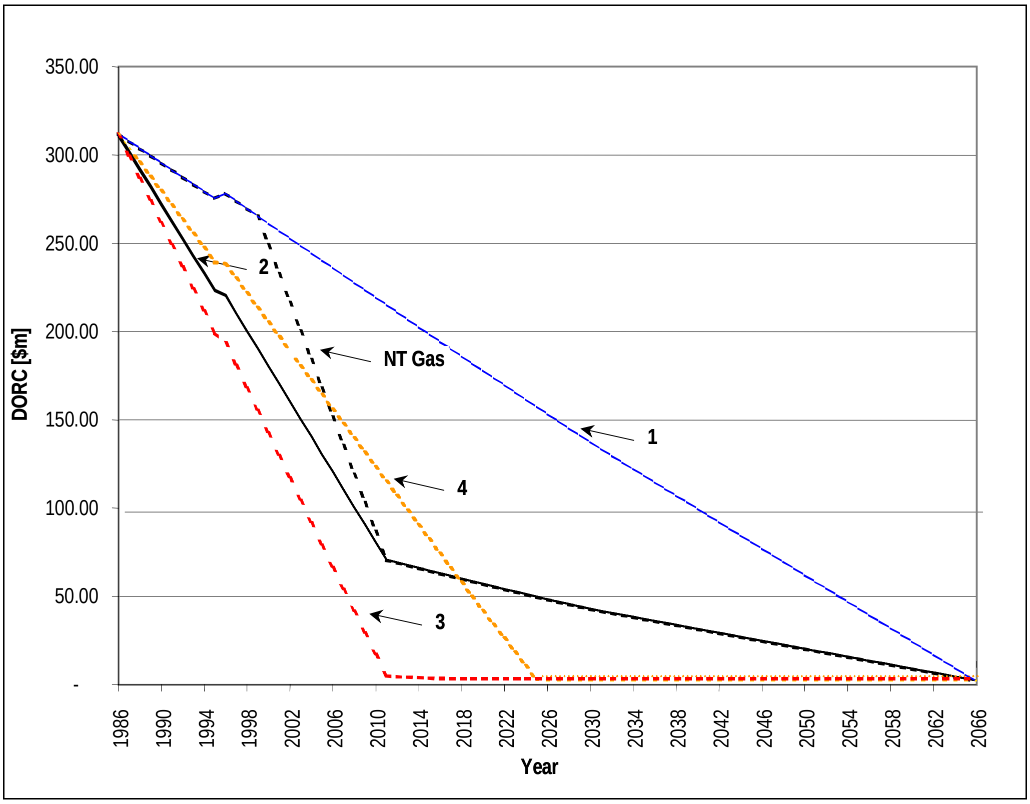
Scenario 2 – accelerated depreciation from pipeline commissioning to 2011, and thereafter standard straight-line depreciation over the remaining technical life of the pipeline – this option retains the residual asset value of $61.84m (at 1 July 2011) recommended by NT Gas;

Scenario 3 – accelerated depreciation from pipeline commissioning to 2011, reflecting an expectation that the pipeline will not be utilised post 2011; and

Scenario 4 – accelerated depreciation from commissioning to 2025, reflecting an expectation that the Amadeus Basin gas fields will be depleted by 2025.

These four scenarios, along with NT Gas' approach, are shown in Figure 2.1.

Figure 2.1: DORC valuation of the ABDP



Source: Connell Wagner, Review of NT Gas' DORC valuation for the ABDP, p. 38.

Based on these four scenarios, Connell Wagner considered that the DORC valuation (as at 1 July 1999) for the ABDP would be likely to fall within the range $155m to $214m (Scenario 3 and Scenario 4 respectively).

Connell Wagner recommended the depreciation approach identified by Scenario 2. In making this recommendation Connell Wagner pointed out that the redundancy risks highlighted by NT Gas may have existed since the initial planning, construction and operation of the pipeline and therefore, depreciation based on an 80-year life may not be appropriate. In view of the limited reserves of the Amadeus Basin, it would be reasonable to expect that pipeline tariffs would be geared to recoup the costs of the assets over a shorter time period. Connell Wagner also noted that while Timor Sea gas and the depletion of the Amadeus Basin is likely to displace northward haulage through the ABDP, it is likely that the pipeline will still provide some back haulage services until the expiration of its technical life. Connell Wagner considered that Scenario 2 reflected the commercial possibilities of the foundation customer contract expiring in 2011 and also the potential usage of the pipeline upon entry of Timor Sea gas.

Connell Wagner used its own asset life assumptions,[23] ORC estimate and the depreciation approach outlined in Scenario 2 to calculate a DORC value for the ABDP of $191m.

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[23] Technical lives assumptions for pipeline assets, rotating equipment, metering equipment and other pipeline facilities (including SCADA) were 70,30, 50 and 15 years respectively.

Depreciated Actual Cost

The Commission also requested Connell Wagner to calculate a DAC for the ABDP using accepted accounting asset lives. In the absence of adequate data, Connell Wagner chose to determine a reasonable range for the DAC valuation.[24] Connell Wagner proposed a range of $145m to $211 as the likely DAC value of the ABDP. This range was established by examining two different possibilities for depreciating the initial cost of the assets:

- Assuming that NT Gas structured tariffs to recuperate all pipeline capital by 2011 (the expiration date of the foundation customer contract) the DAC as at 1 July 1999 was $145m.
- Assuming that NT Gas structured tariffs to recuperate all pipeline capital by 2025 (the expected depletion date for gas reserves in the Amadeus Basin) the DAC as at 1 July 1999 was $211m.

Purchase price

In other access arrangements, the Commission has also relied upon recent sale price as a guide or check on the current value of the pipeline's assets. In theory a purchaser would pay an amount up to the net present value of future earnings expected from the assets. The Commission requested NT Gas to provide it with the price paid by AGL in 1988 for its 96 per cent share in NT Gas. Agility responded on behalf of NT Gas, stating that providing the information would involve a significant amount of time and cost and that the sale price would not provide any meaningful information as to the value of the pipeline at the time of AGL's share acquisition.[25] In the *Draft Decision*, the Commission did not accept this view and considered that it is necessary to examine the issue further.

2.3.2 NT Gas' response to the Connell Wagner report

Venton & Associates review of the Connell Wagner report

NT Gas was provided with a copy of Connell Wagner's draft report for comment.[26] Venton & Associates (Venton) were engaged by NT Gas to provide comments on the technical and cost estimate matters in the Connell Wagner report.

The Venton report identified a number of areas where it believed the Connell Wagner optimised design was deficient, including:[27]

- non commercial pipe steel grade and inadequate pipe wall thickness selection;
- an apparent over-optimistic hydraulic performance of the pipeline resulting in fewer initial compressor stations being installed than are actually required;

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[24] The actual cost assumed was $329 million. This is an average actual cost based on the capital additions and asset disposals from 1986 to 1999.

[25] Agility letter to ACCC, 23 February 2001.

[26] Connell Wagner's final report did not differ substantially from its draft report.

[27] Venton & Associates, *NT Gas DORC Review of Connell Wagner ACCC Submission*, 5 September 2000, p 1.

- estimating unit costs that appear lower than industry norms for the size proposed;
- estimated costs for compressor stations and meter regulating stations that are lower than current development costs for similar installations in Australia.

Venton also reassessed NT Gas' ORC estimate to account for interest during construction, native title costs and inconsistencies in compressor station costs – areas identified by Connell Wagner as missing or overlooked by NT Gas. The allowance for native title and cultural heritage costs was estimated by Venton to be approximately $10m.[28]

In its report, Venton stated that when allowances were made to both the Connell Wagner and NT Gas estimates to include these omissions or deficiencies,[29] the estimated cost of each 'optimised' design increased substantially. Connell Wagner's optimised cost increased from $308m to $351m[30] and NT Gas' optimised cost (replacing the existing system) was increased from $319 to $345.

Venton also responded to Connell Wagner's suggestion that the accuracy of the NT Gas and the Connell Wagner estimates was ±25 per cent.[31] They argued that if this error level is correct, then each estimate lies within the error band of the other, and hence it is wrong to draw a conclusion that one design is optimal compared to another.

2.3.3 Connell Wagner's response to the Venton & Associates report

After reviewing Venton's comments in response to its desktop audit of the initial capital base, Connell Wagner submitted a number of comments to the Commission to address the key areas of discrepancy between Venton and Connell Wagner.[32] Connell Wagner did not agree with the majority of Venton's criticisms.

In accordance with the Commission's terms of reference, Connell Wagner utilised the base case scenario gas flow forecast. Therefore, the design gas flow used for consideration by Connell Wagner in its report and the resulting optimum design were based on different assumptions than that used by Venton in its analysis of NT Gas' modelling.[33]

Connell Wagner stated that Venton appeared to have assumed that Connell Wagner used a conceptual design for compressor stations assuming three compressor units. Venton proposed a total of $20.4m be added to Connell Wagner's cost estimate for the

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28 Venton & Associates, *NT Gas DORC Review of Connell Wagner ACCC Submission,* 5 September 2000, p 6.

29 No adjustment was made for 'unit' construction cost differences.

30 Venton & Associates note that if no adjustment is made to the Connell Wagner compressor installation schedule, their estimated cost would increase to $337.

31 Venton comments were based on Connell Wagner's draft report which estimated an accuracy level of ±25%. This estimate was later refined in the final report to –5+15% with 75% confidence.

32 Connell Wagner letter to Commission, 29 November 2000.

33 NT Gas' ORC estimate was based on the optimal design for the high and base case throughput scenarios.

compressor stations. However, Venton did state that if the Connell Wagner compressor installation schedule were correct then this would be reduced to $6.4m.[34] Connell Wagner stated that it had not made provisions for more than two compressor units at any location and considered its original cost estimate for each compressor station to be reasonable.[35] Modelling undertaken by Connell Wagner indicated that two compressor stations were more than sufficient.

Connell Wagner's design grade of steel could be considered as non-standard but still acceptable under the API 5L Specification for Line Pipe.

The wall thickness for the Channel Island extension may need to be increased. The cost difference between Connell Wagner's assumed wall thickness and Venton's was $250,000.

Connell Wagner agreed with Venton that if a second compressor unit was added after the station was completed, the cost would be higher. However, Connell Wagner assumed that both compressor units would be installed at the same time. The second compressor unit rate should not be equal to the first unit, as infrastructure costs are included in the unit rate for the first compressor.

While there is no reason to believe the Venton allowance for native title compensation payments is wrong, Connell Wagner recommend that historical (actual) compensation payments be considered as the most appropriate guide in this instance. In the absence of this information Connell Wagner estimated a native title allowance of $5m, compared to Venton's $10m.

Venton commented that the discount project cost analysis carried out by Connell Wagner was superficial. Connell Wagner considered Venton's remarks in this regard were not significant as all of the modelling employed, parameters used and options considered by Connell Wagner in its analysis had not been available to Venton.[36]

2.4 Commission's Draft Decision

Optimised replacement cost

In its access arrangement, NT Gas expressed considerable uncertainty about estimates of pipeline throughput for the 30-year period to 2029. This is due to the expiration of its foundation contract in 2011 and a lack of information regarding future production expectations of the existing Amadeus Basin fields.[37] In light of the uncertainty over ORC valuations (in that it is a theoretical exercise) and throughput estimates over the 30-year period, NT Gas nominated its estimated replacement cost of $318.96m as the appropriate ORC valuation for the ABDP.

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34 Venton & Associates, *NT Gas DORC Review of Connell Wagner ACCC Submission*, 5 September 2000, p 7.

35 Connell Wagner valued the first compressor at $6.5m and the additional compressor at $4.3m.

36 Connell Wagner letter to Commission, 29 November 2000, p. 4.

37 Access Arrangement Information, p. 18.

In addition to engaging Connell Wagner to review NT Gas' ORC, the Commission also conducted its own in house assessment. Although its ORC was derived independently from the other analysis, the Commission obtained an optimal configuration almost identical to that of Connell Wagner's. On the other hand, despite starting with similar assumptions on the appropriate demand scenario, NT Gas determined a different optimal configuration. Comparisons of the various optimal configurations are discussed in the *Draft Decision*.

In its ORC analysis NT Gas considered three different demand scenarios when determining the appropriate valuation for the ABDP– a base, base reduced and a high case. NT Gas' calculated its ORC value of $335m based on the optimal configuration obtained from both the high and base case scenarios. However, the Commission considers the base reduced case scenario a more appropriate basis for determining the ORC valuation for the ABDP. NT Gas' uncertainty about future pipeline throughput supports the view that the most likely demand scenario is represented by the base reduced case. NT Gas' own ORC calculations using the base reduced case yielded an optimal configuration valued at $313m, which is lower than its proposed existing system ORC of $318.96m.

The Commission concurs with Connell Wagner's view that an assessment term of 15 years, compared to NT Gas' 30 year term, is a more reasonable time frame for the NPV analysis of pipeline system costs. A similar 15-year time horizon was proposed by EAPL in its evaluation of the ORC for the Moomba to Sydney pipeline (MSP) system.[38] The Commission therefore adopted the more conservative time horizon of 15 years in its analysis.

Based on its own optimal configuration, the Commission calculated an ORC of $322m as at 1 July 1999 in its *Draft Decision* for the ABDP.

Consideration of Agility's DORC proposal

Subsequent to NT Gas' original proposal, Agility on behalf of NT Gas, proposed an alternative methodology for constructing the DORC valuation from the estimated ORC. Broadly, Agility emphasised that the DORC derivation from ORC should be independent of the past or proposed frameworks for establishing tariffs. Instead, the value of the assets for regulatory purposes should be based on the NPV of revenues that could be generated by the assets over their remaining useful life as if tariffs were set on the basis of what would be charged by a new entrant in a contestable market.[39] As the new entrant would be constrained in a contestable market by the costs of other potential entrants the tariff and revenue profile over time would need to reflect the impact of changes in its costs, particularly replacement costs.[40] The outcome of applying this

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38 ACCC, Access Arrangement by East Australian Pipeline Limited for the Moomba to Sydney Pipeline System, *Draft Decision*, 19 December 2000, p. 18.

39 *Construction of DORC from ORC*, Agility Management, August 2000.

40 If there were no cost changes over time, the revenue stream would take the form of an annuity. However, if there were technological changes taking place continuously there is likely to be a downward movement in revenues over time, at least in real terms. If costs (e.g. materials and construction) were increasing at a faster rate than inflation, revenues and tariffs could be expected

approach is that, for reasonable assumptions about the rate of technological change, the DORC value begins to deviate significantly from the ORC estimate only towards the end of the life of the asset.

According to Agility, the ratio of DORC to ORC for the ABDP was most likely to be in the range of 96 to 99 per cent. This would result in a DORC value of between $331m to $341m.[41] Agility's approach is concerned with establishing the value of DORC, which under the Code, is normally the upper limit of the value of the initial capital base. However, Agility acknowledges that the regulator must also take other factors into account when setting the value of the initial capital base.[42]

Following Agility's submission of its revised approach for the calculation of DORC the Commission questioned Agility whether the accelerated depreciation profile proposed by NT Gas had been considered in the context of Agility's new approach for calculating DORC. In response, Agility stated that the accelerated depreciation profile was not explicitly taken to account in the revised DORC calculation.

The *Draft Decision* did not consider Agility's proposed methodology (as outlined in section 2.2.1) to be appropriate for regulated gas assets for two main reasons:

- Agility's approach was deemed inconsistent with the depreciation proposed in the regulatory framework and the historical treatment of depreciation for the purpose of setting tariffs. It therefore loses its relevance for setting an initial capital base which needs to comply with fairness requirements of the Code, (sections 8.10(f) and (g) in particular); and

- the hypothetical contestable model used to establish the revenue profiles of new and existing assets has limited relevance to the regulated gas pipeline industry where prices are established on the basis of straight line depreciation.

Depreciation

The Commission considered that the DORC valuation, as calculated by NT Gas, did not provide an appropriate valuation of the ABDP's pipeline assets. It was the Commission's view that the risk of stranding currently faced by the pipeline was evident during the construction of the pipeline. The evidence of this risk led the Commission to believe that the appropriate valuation for the ABDP's pipeline assets lay below that established by NT Gas' proposed DORC.

The Commission was of the view that the ABDP had been facing a risk of stranding since it was commissioned in 1986. Specifically, the existence of the 2011 residual value of $61.84m for the leased pipeline assets prior to 1999 led the Commission to believe that the earning potential of the ABDP was expected to be significantly reduced by 2011. The expiration date of the foundation contract combined with the increasing

to increase in real terms over time. Such modifications to annuities are sometime referred to as 'tilted annuities'.

41 Based on Venton & Associates re-assessment of ORC to $345m.

42 Section 8.10 of the Code.

uncertainty regarding remaining accessible reserves in the Amadeus Basin further supported the Commission's view.

After consideration of the factors given above and other confidential information, the Commission determined an ICB of $198.8m for the ABDP as at 1 July 1999. To calculate its ICB the Commission depreciated ORC on the following basis:

- pipeline assets were depreciated (straight line) based on the residual value of $61.84m at 1 July 201l, assuming that 13 years of the asset's life has already expired.

- all other asset classes were depreciated (straight-line) based on their remaining economic lives.

Deferred tax liability

The Commission included an adjustment to the ICB to account for NT Gas' deferred tax liability ($12.9m at 1 July 1999). The rationale for this adjustment is set out in the *Draft Decision*.

Initial capital base as at 1 July 2001

Taking the ICB valuation at 1 July 1999 of $185.8m and adjusting it for the deferred tax liability, as well as inflation,[43] capital expenditure and depreciation until 1 July 2001, the Commission calculated an initial capital base of $176.2m for the ABDP in its *Draft Decision*.

2.5 Submissions by interested parties

The majority of submissions received by the Commission focussed on the appropriateness of the proposed ICB. Woodside and Shell submitted that the proposed DORC value appeared too high. They also questioned the merits of using a DORC valuation because 'the economic theory does not produce a reasonable and/or acceptable competitive tariff' and 'incumbents are able to 'double dip' economic value'.[44]

Woodside and Shell further stated:

> A more realistic asset valuation would be somewhere in between DORC and depreciated value [DAC]. This would seem to be consistent with the realities of a competitive market place where the pricing point is never a precise formula driven number but rather, a market driven price, sitting somewhere in between the short term marginal cost and the long run economic average cost as determined by the mechanisms such as DORC.[45]

In its submission on the Issues Paper, NT Power Generation (NTPG) also considered the DORC valuation to be too high and significantly influenced by the methodology

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43 The actual inflation rate of 3.2 per cent was used for the year ending 30 June 2000 and a forecast inflation rate of 1.96 per cent was used thereafter.

44 Woodside Energy and Shell Development (Australia) submission, 9 September 1999, p 3.

45 Woodside Energy and Shell Development (Australia) submission, 9 September 1999, p 3.

used to determine accumulated depreciation of the pipeline asset. In particular, NTPG considered accumulated depreciation of $48.81m used in the DORC valuation to be much too low, and suggested that accumulated depreciation in the order of $92m[46] would be more appropriate. NTPG contended that this would correspond well with the $98.5m, which NT Gas considered to be a reasonable estimate of accumulated depreciation for the calculation of DAC.[47]

The Commission understands that the NTPG has withdrawn from the NT electricity market with announcements regarding this appearing in the press[48]. However, the Commission is of the view that NTPG provided valuable input into the public consultation phase of the *Draft* and *Final Decisions* for the ABDP access arrangement. The Commission therefore will have regard to the comments of NTPG particularly as it was the only third party, besides PWC, with access to the ABDP and was one of few entities with knowledge regarding the operation of the ABDP and the NT energy sector.

Furthermore, despite favouring DAC as the appropriate asset valuation methodology in this case, NTPG believed the $234.7m DAC valuation proposed by NT Gas was too high given that there was excess capacity on the pipeline at the time of commissioning.[49]

In its submission to the *Draft Decision*, NTPG contended that the optimised design adopted by Connell Wagner supported its assertion that, apart from the Channel Island extension, the pipeline was initially oversized and consequently the initial capital investment was higher than would have been incurred by a prudent operator.[50]

Nabalco also supported the use of DAC in establishing the ICB. In particular, Nabalco believed that the DORC methodology overvalues assets and does not accurately reflect the actual investment cost incurred.[51]

2.6 NT Gas' response to the *Draft Decision*

In its submission, NT Gas objected to the ICB proposed by the Commission in its *Draft Decision*. NT Gas' comments generally centred on two main issues:

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46 NTPG has calculated this using the 'unit of throughput' depreciation approach, and suggests accumulated depreciation of the ABDP facilities to date should be about 19% of original cost ($61.7m in 1986 dollars or $92m in 1999 dollars)

47 NTPG submission, p. 3.

48 Northern Territory News, *Excluded from Gas Supply*, 12 September 2002, p.4

ABC Top End, Morning Show: Interview between Fred McCue (compere) and Mr Paul Everingham, Chair, NTPG. September 11, 2002. Transcript supplied by Media Monitors.

49 NTPG submission, p. 3.

50 NTPG submission, 2 August 2001, p. 2.

51 Nabalco submission, p. 2.

- The Commission's approach to deriving the DORC for the ABDP, and the value of the DORC derived, was inconsistent with the Commission's stated interpretation of DORC.

- In the view of NT Gas, it was not clear that the *Draft Decision* had properly taken into account the range of matters described in section 8.10 and 8.11 of the Code.

Construction of DORC from ORC

In its response to the *Draft Decision*, Agility reiterated its approach to the construction of DORC from ORC that it proposed to the Commission in August 2000 and which is discussed in section 2.4. Agility argues that its approach is consistent with the Commission's *Draft Regulatory Principles*. Agility commissioned Professor Stephen King as a consultant to advise on this matter and states that Professor King supports Agility's approach. According to Agility, Professor King considered that:

- Agility's approach is consistent with the *Draft Regulatory Principles* and the interpretation of DORC presented in the Commission's Victorian gas decision;

- the straight line adjustment adopted by the Commission in the *Draft Decision* is arbitrary, lacks economic justification and is inconsistent with the *Draft Regulatory Principles* and previous decisions;

- past levels of recovery of depreciation are irrelevant to the construction of DORC from ORC; and

- the depreciation schedule implicit in the construction of DORC from ORC does not place any constraints on the depreciation schedule of the initial capital base contained in the access arrangement.

NT Gas contended that the DORC value derived consistently with the Commission's stated interpretation of DORC was at least \$290m.[52] NT Gas noted that the Commission has previously stated that it favours DORC for establishing the capital base and therefore the initial capital base should be at least \$290m instead of the \$199m proposed in the *Draft Decision*.[53]

Other considerations in establishing the initial capital base

NT Gas stated that it was not clear from the *Draft Decision* whether the Commission had taken into account all the factors in section 8.10 of the Code, other than DORC and DAC, when setting the initial capital base. NT Gas also noted that the possibility that values, such as the residual value, book or economic depreciation, may not be wholly accurate does not preclude the Commission from taking them into account and, in fact, section 8.10 requires the regulator to do so.[54]

NT Gas also noted that section 8.11 of the Code states that the initial capital base valuation should normally not fall outside the range of values determined by DAC and

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52 Based on the proposed ORC of \$322m in the *Draft Decision*.

53 NT Gas submission, 14 November, p. 1.

54 NT Gas submission, 14 November, pp. 11 – 12.

DORC. NT Gas argued that the Commission must take all of the valuations into account and, if circumstances warrant, it is within the Commission's discretion to establish an initial capital base in excess of DORC.[55]

NT Gas noted that the *Draft Decision* appeared to assume that the ICB should be set at a level where NT Gas would recover no more than the original capital cost of the pipeline over its life. It was asserted that the Code makes no reference to 'windfall gains' (or their avoidance) and it imposes no requirement that the initial capital base be established so that the cost of pre-existing assets is depreciated only once.[56]

With regard to the development of Timor Sea gas fields, NT Gas stated that it is uncertain how and to what extent the development will affect the ABDP and given this uncertainty, it is inappropriate to establish the ICB on the assumption that usage of the ABDP will decline substantially after 2011.[57] However, in its proposed access arrangement, NT Gas accepted there is significant uncertainty regarding usage for the ABDP after 2011[58]. In this *Final Decision*, the Commission considers this issue in more detail in sections 3.3.2 to 3.3.6 and concludes that there is a possibility of reduced utilisation of the ABDP after 2011.

2.7 Determining a DORC valuation for the *Final Decision*

Section 8.10 of the Code suggests a range of valuation approaches that should be considered when establishing the initial capital base for an existing pipeline. The Commission has considered the information contained in NT Gas' access arrangement information and NT Gas' response to the Commission's section 41 Notices[59] as part of its considerations under section 8.10 of the Code.

The Commission's Final Decision ORC

In its *Draft Decision*, the Commission determined an ORC valuation of $322m, however, the Commission has since updated the ORC determination carried out for the *Draft Decision* to an estimate based on 1 July 2001 costs. The Commission's 2001 estimate of ORC has increased by about 16% in comparison with the earlier estimate. A portion of this increase can be attributed to changes in the cost estimation methodology, however the majority of the increase results from taking into account the impact of general cost increases (as measured by the CPI) and the relative decline in the value of the Australian dollar over the period by comparison with the US dollar. A comparison of the different ORC valuations can be seen in Table 2.3.

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55 NT Gas submission, 14 November, p. 11.

56 NT Gas submission, 14 November, pp.11 – 12.

57 NT Gas submission, 14 November, p. 15.

58 NT Gas Access Arrangement Information, p.18

59 On 20 August 1999 and 11 July 2001, the Commission issued notices under section 41 of the Gas Pipelines Access Law on NT Gas for required information. This information included: the existing transportation contracts for the ABDP; a copy of the independent auditors' report of the asset valuation; electronic copy of all financial models and revenues earned under existing contracts.

Table 2.3: Comparison of ORC valuations

Cost in $m	NT Gas proposed[(a)]	Connell Wagner[(a)]	ACCC Draft Decision[(a)]	ACCC Final Decision[(b)]
Transmission pipelines	300.3	257.4	256.4	288.1
Compressors	7.0	21.6	20.8	35.8
Regulating, metering, odourisation	10.0	5.0	7.0	7.3
SCADA and communications	1.6	0.7	4.7	5.3
Linepack	0.0	0.0	0.0	0.0
Operations facilities	0.0	6.7	8.3	11.1
Native title allowance	0.0	5.0	8.3	8.3
Sub-total	318.9	296.4	305.5	355.9
Interest during construction	0.0	12.1	16.8	17.8
Total	**318.9**	**308.5**	**322.3**	**373.7**

Notes: (a) as at 1 July 1999.
(b) as at 1 July 2001.

It appears that in its ORC valuation, NT Gas has either not shown or omitted separate allowances for native title, operations and maintenance facilities of a capital nature and interest during construction. It is unclear whether such allowances have actually been provided for by NT Gas or whether they were included under other headings.

Detailed estimates, provided to the Commission by NT Gas on a confidential basis, show that a general contingency, typically amounting to 10 per cent of the total, has been included for each main pipeline segment. While the inclusion of such an allowance might be justified under certain circumstances (for example, when budgeting for a new project to place a cap on the total cost), it is not considered appropriate in a regulatory sense for determining the replacement cost of an existing pipeline.

However, NT Gas may have considered the general contingency a sufficient provision to cover allowances for native title and interest during construction, although this has not been stated. The most recent Venton review, commissioned by NT Gas, has made what it regards as an appropriate adjustment for native title and interest during construction (all adjustments proposed by Venton are shown in separate columns in the table above). The Venton review does not provide reasons for such adjustments other than to assume they have been overlooked in NT Gas' detailed costing. The Connell Wagner report makes a similar assumption.

Venton's total proposed adjustment for these two possible significant omissions in the NT Gas estimate is $22m. Coincidentally, the total of the general contingency amounts shown in NT Gas' detailed costing of its replacement option is $23m, so the net effect of any decision by the Commission to disallow the general contingency but to allow adjustment for native title and interest during construction has little effect on the total cost.

The ORC valuation of $373.7m includes estimates for components greater than that proposed by NT Gas and reflects cost changes to certain assets that comprise the ORC valuation for the ABDP assets, since the release of the *Draft Decision*.

It is the Commission's view that the legitimate interests of the service provider under section 2.24(a) of the Code provides for the inclusion of the most up to date costings for the components for the ORC valuation for the ABDP. Based on its own analysis, the Commission proposes to adopt an ORC of $373.7m as the basis for the calculation of DORC in this *Final Decision.*

2.7.1 Depreciation of ORC

Commission's depreciation of ORC

In this *Final Decision,* the Commission determined a DORC valuation based upon ORC multiplied by the remaining useful life of an asset divided by the useful life of a new replacement asset. Based upon this approach, the ABDP's ORC valuation of $373.7m was depreciated to a DORC valuation of $304.5m for the pipeline as at 1 July 2001. In this DORC calculation, the Commission has assumed an optimistic outlook for the ABDP based upon the continued operation of the pipeline beyond 2011, the date after which the pipeline's usage is likely to be reduced, due to the possibility of it providing backhaul services for gas from Timor Sea, for example. In the *Draft Decision*, this possibility led the Commission to believe that the ABDP may continue to hold, albeit, limited economic value after 2011. However, this possibility like others raised in this *Final Decision* represents one of many scenarios that may affect the ABDP.

Commission's depreciation of ORC

As mentioned previously, the Commission does acknowledge that the ABDP is at risk of reduced usage after 2011. In this circumstance, the remaining useful life of the ABDP could be shorter than the technical life of the pipeline or that of a replacement represented by a new entrant.

In this *Final Decision*, the Commission has considered the possibility of reduced utilisation after 2011 and based upon this scenario derived a traditional straight-line DORC approach. Accordingly, DORC has been determined as the ORC multiplied by the ratio of the ABDPs remaining useful life over the useful life of a new asset. In relation to the ABDP, its remaining useful life would tend toward the useful life of a new asset, both of which are constrained by the possibility of reduced utilisation after 2011. In that instance the DORC values tends towards an ORC value. The DORC valuation that results for the ABDP of $373.7m represents the upper valuation that DORC may take given the possible stranding scenarios that could take place.

2.7.2 Commission's considerations regarding DORC and the ICB

The Code requires that the regulator determine a DORC valuation as part of determining the ICB for the first access arrangement for a pipeline that existed prior to the commencement of the Code. The Commission has been required to consider a range of issues in relation to the application of the DORC asset valuation methodology when applying it to the ABDP. Since the *Draft Decision*, further work has been undertaken by the Commission and others in relation to the derivation of a DORC value for the ABDP.

The Commission has also considered the following documents as part of the *Draft Decision and Final Decision*:

- Connell Wagner's report on the DORC valuation for ABDP;
- Venton and Associates' review of the Connell Wagner report;
- Connell Wagner's response to the Venton report;
- Agility's revised approach to the construction of DORC from ORC and professor Stephen King's report on Agility's approach;

In relation to the *Final Decision*, the Commission has considered a report prepared by Sinclair Knight Merz (SKM) on the depreciation within DORC for the ABDP.

Sinclair Knight Merz Report on depreciation within DORC for the ABDP[60]

The Commission sought advice from SKM regarding the use and calculation of DORC for valuing the ICB for the ABDP. Specifically, the Commission asked:

> *Given the specific circumstances of the ABDP, is DORC a meaningful concept, and if so, what is an appropriate method for calculating DORC?*

SKM recommended a 'mechanistic' approach to the calculation of DORC and that, to the greatest extent practicable, judgement and policy elements should be handled outside the calculation of the DORC. SKM considered that judgement and discretion should be exercised in accordance with the provisions of sections 8.10 and 8.11 of the Code when considering the valuation of the ICB, as distinct from DORC.

SKM also concluded that DORC was a meaningful concept given the circumstances (eg the risk of stranding) of the ABDP. Under SKM's approach, DORC is calculated by depreciating ORC on a straight-line basis using the economic life of the asset. SKM considered the key element in applying this methodology for the ABDP was the assessment of the economic life of the pipeline's assets. This would be determined by identifying various stranding scenarios (credible scenarios) for the ABDP by certain dates and then providing them with relative weightings and then aggregating them to determine a single effective (economic) life for the pipeline. SKM suggested that a single 'expected value' that results from that process would form the basis of the economic life element of the DORC calculation.

SKM also noted that there were equivalent methods that could arrive at the same value as its 'probability weighted economic life' approach. SKM considered that the Commission's methodology for calculating DORC in its *Draft Decision*[61] could be one

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[60] Sinclair Knight Mertz (2002), *Depreciation within DORC*

[61] The DORC for the ABDP's pipeline assets was calculated based on the depreciation of ORC to a residual value of $61.84m.

of these equivalent methodologies, provided the parameters for the calculation took into account the ‘credible scenarios’ discussed above.

Agility’s response to the SKM report

The Commission provided Agility on behalf of NT Gas with an opportunity to comment on the SKM report regarding the use and calculation of DORC for valuing the ICB for the ABDP. Despite this opportunity, Agility did not provide a response to the issues raised by the report.

Commission’s assessment

In assessing the various DORC and DORC-based valuations, the Commission has been guided by the advice of SKM that concluded that DORC should be determined based solely upon the economic principles that underpin it, resulting in a stand-alone and independently reproducible valuation that excludes other factors that the regulator may take into account when establishing an ICB. The requirement to consider the other factors listed in the Gas Code is provided for outside the DORC process as set out in section 8.10(c) through to section 8.10(k) of the Code[62].

As mentioned previously, the Commission does acknowledge that the ABDP is at risk of potentially reduced usage caused by a combination of the expiration of foundation contracts in 2011, the potential for by-pass caused by gas from the Timor Sea being transported by a new pipeline and the expected depletion of the Amadeus Basin sometime after 2011. Given these circumstances, the ABDP’s (or a possible replacement pipeline’s) economic life maybe ‘capped’ by reduced utilisation after 2011 and is a period of time that is shorter than the technical life of the pipeline.

The Commission has traditionally determined DORC as the ORC multiplied by the ratio of the existing pipeline asset’s remaining useful life over the useful life of a new asset. In relation to the ABDP the potential risk of stranding after 2011 aligns the ABDP’s remaining useful life with the useful life of a new replacement pipeline asset. In that instance the DORC value tends towards ORC. The valuation that results might be described as a ‘maximum’ value for DORC for the ABDP of $373.7m. This represents the upper valuation for DORC given the likelihood of reduced usage or the possibility of stranding after 2011.

The Commission also determined a DORC valuation based upon the remaining economic life equating to the technical life of the ABDP in recognition that there is likely to be, a limited economic value, if the pipeline were to continue operating after 2011. This may occur if the pipeline is providing back haul service for gas projects off Australia’s northern coast. This DORC valuation of $304.5m incorporates the more optimistic assessment of the remaining useful life of the ABDP.

The Commission acknowledges that reflecting too many issues within a single instrument such as DORC, reduces the transparency of the ICB setting process and it is therefore desirable to determine DORC as a stand-alone value with other factors considered separately when determining the ICB. It is the Commission’s view that

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[62] Sinclair Knight Mertz (2002), *Depreciation within DORC*, p.7

approaches to the determination of DORC that depart from the economically sound derivation of DORC are therefore contrary to good regulatory practice.

The table below provides an overview of the differing approaches that the Commission has considered as part of this *Final Decision* in determining a DORC valuation.

Table 2.5: Comparison of DORC and DORC-based ICB valuations

Methodology	Key Assumptions	Valuation
DORC tends to ORC	▪ DORC tends towards ORC – this occurs when the remaining useful life of the ABDP and the useful life of a new pipeline are similar due to the recognition of the possible reduction in pipeline utilisation beyond 2011. ▪ ORC value of $373.7m	DORC tends towards ORC of $373.7m as at 1 July 2001
Agility DORC	▪ Agility's NPV of future revenue approach. ▪ Based upon an ORC of $345m.	$331 – 341m
Traditional DORC	▪ DORC is determined as the ORC times the ratio of the remaining useful life of the ABDP divided by the useful life of a new replacement pipeline. This assumes the pipeline will continue to operate beyond 2011 until the end of its useful life. ▪ ORC value of $373.7m	$304.5m as at 1 July 2001
NT Gas DORC	▪ Straight-line depreciation on the economic life of the ABDP until 2066. ▪ Based on NPV of lowest capital and maintenance costs out to 2029.	$265m as at 1 July 1999
Draft Decision DORC	▪ Straight-line depreciation to a residual value of $61.48m in 2011, straight-line thereafter. ▪ All other non-pipeline assets were depreciated on a straight line basis.	$176.2m
Connell Wagner	▪ Identified four possible depreciation scenarios based upon the risk of stranding for the ABDP. ▪ Recommended scenario that utilised straight-line depreciation until 2011, thereafter straight-line over the remaining technical life of the ABDP. ▪ ORC value of $308m	$191m

The Commission notes the proposed Agility valuation of between $331m and $341m for the ABDP ICB. This is within the range of the DORC valuations that the Commission determined. However, the Commission is concerned that an ICB within the range of $304.5 and $373m would not produce a meaningful reference tariff in the context of the ABDP. It is the Commission's view that the risk of stranding would imply that the ICB could not be recovered, through reference tariffs based on a DORC range of $304.5 to $373.7m, by the likely stranding date around 2011.

The Commission accepts that a DORC valuation for the ABDP is likely to be between $304.5m and $373.7m, which also includes Agility's proposed DORC valuation. The Commission has chosen not to determine a specific DORC as this would involve making an assumption about the likelihood of the pipeline being subject to reduced utilisation after 2011 or possibly being stranded and although stranding is likely, the possible timing of such an event remains unclear.

2.8 Commission's consideration of ICB valuation methodologies

In addition to DAC and DORC under sections 8.10(a) and (b) respectively, the Code requires the Commission to consider other well-recognised asset valuation methodologies in establishing the initial capital base (section 8.10(c)). The Commission has considered the DORC valuation as required by section 8.10(b) of the Code in section 2.7. This section takes account of other valuation considerations.

2.8.1 Depreciated Actual Cost

Depreciated Actual Cost (section 8.10(a));

NT Gas calculated a DAC of $234.7m for the ABDP as part of its proposed access arrangement. Because the ADBP is a leased asset NT Gas has not been obliged to calculate accumulated depreciation for statutory accounting purposes. Therefore, the DAC proposed by NT Gas is essentially an estimate, calculated on the basis of 'reasonable accounting standards.' No indication of the asset life assumptions used to calculate the accumulated depreciation was provided by NT Gas.

As discussed earlier, Connell Wagner was also asked by the Commission to calculate a reasonable DAC for the ABDP. Connell Wagner's analysis provided a range of $145m to $211m for the DAC based on the assumption that NT Gas structured its tariffs to recuperate all pipeline capital by 2011 and 2025, respectively.

In many instances, regulators have found calculating an accurate DAC problematic due to data either being unavailable or inadequate. Based on available information however, the Commission has calculated a DAC of $179.3m (as at 1 July 2001), based on the original cost of the pipeline, lease amortisation schedule and other confidential documents. The Commission also made allowances for the inclusion and depreciation of capital additions and disposals that occurred after the pipeline was commissioned. The Commission used this valuation as part of its deliberations for the *Final Decision*.

2.8.2 Other well recognised asset valuation methodologies

Values that would result from applying other well recognised asset valuation methodologies in valuing the Covered Pipeline (section 8.10(c));

Residual value

In relation to other pipelines, the Commission has considered the residual value (based on economic depreciation) a useful guide in assessing the appropriateness of the initial capital base. In this case however, the extended time frame over which the residual value was calculated resulted in an excessively high valuation, which was well in excess of not only the DORC range of ($304.5m and $373.7m) but also the ORC valuation of $373.7m.

Section 8.11 of the Code states that the initial capital base valuation normally should not fall outside the range of values determined by DAC and DORC. As noted above, in this instance, the residual value calculated by the Commission was well in excess of DORC, although this does not prevent the Commission considering the residual value. However, as noted in the *Draft Decision*, NT Gas noted that the use of the residual valuation approach produced a value in excess of DORC, and suggested that the DORC methodology was more appropriate[63].

Optimised Deprival Value

As mentioned previously, the Code requires the regulator to consider a range of factors when determining an ICB. The Regulator may consider recognised asset valuation methodologies other than DAC and DORC, one such valuation methodology is Optimised Deprival Value (ODV).

The ODV approach requires calculating DORC and Economic Value (EV), which is the maximum of the realisable (scrap) value and the present value of the after tax cash flows, and then selecting the lesser of DORC and EV[64]. The resulting ODV provides a measure of the compensation that a firm would require to fully offset it being deprived of an asset.

The ODV asset valuation methodology may be applied when it is not possible for a firm to earn sufficient long run profits to provide an appropriate return on a DORC-determined asset base[65]. This is the situation with the ABDP where DORC tends toward ORC and the possibility that the ABDP could have a reduced economic life beyond 2011. This means that it would be unlikely that a firm would earn sufficient revenue to recover a DORC-asset valuation within that time period.

In the situation of the ABDP, if a new asset were constructed it would be necessary to recover most of the capital employed over a relatively short time period. The typical

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63 Access Arrangement Information, p.15.

64 New Zealand Ministry of Economic Development (2000), *Handbook for Optimised Deprival Valuation of System Fixed Assets of Electricity Line Businesses*, p.15

65 New Zealand Ministry of Economic Development (2000), *Handbook for Optimised Deprival Valuation of System Fixed Assets of Electricity Line Businesses*, p.15

advantage a new asset has over an existing one is that the new asset will earn revenue over a longer period. This would not be case with the ABDP[66].

As discussed in section 3.6.4, following the release of the *Draft Decision*, information provided to the Commission by NT Gas revealed two additional cost components of which the Commission was not previously made aware. The Commission considers that both additional cost components represent legitimate costs to NT Gas and failure to include them in the calculation of total revenue may result in cash flows insufficient to cover NT Gas' actual costs.

While the second of these cost components has been included in the cash flows as a component of the building block, the first component represents the return of actual capital costs incurred during the construction of the ABDP. Therefore, the Commission considers it appropriate to include the NPV of these costs, in addition to the lease payments, in the valuation of the ODV.

NT Gas' lease obligations and the special asset class costs cover the original cost of constructing the pipeline. However, NT Gas has also undertaken additional capital expenditure since the lease arrangement was finalised, therefore, NT Gas would also have a reasonable expectation that it would earn a reasonable rate of return on this investment.

The Commission is of the view that the ODV approach to the valuation of the leased assets, plus allowances for an additional capital component associated with the construction of the ABDP along with the inclusion of assets outside the lease agreement produce an ICB that will enable the general protection of the legitimate interests of the service provider by allowing recovery of relevant costs. The Commission has therefore been able to determine an ODV based valuation for the ABDP of $228.5m as at 1 July 2001.

It is the Commission's view that consideration of sections 8.10(c) relates to contractual issues that are confidential in nature. Accordingly, a more detailed discussion of the determination of the ICB and additional information relating to the values that underpin the capital base are discussed in Confidential Annexure C

NT Gas's ODV

The Commission has considered the ODV valuation of $308.9m provided by NT Gas as part of its original access arrangement. The Commission notes that NT Gas' ODV valuation is within the estimated DORC range of $304.5m and $373.7m and, as noted in the DORC discussion above, is concerned that such a valuation would be unlikely to be recovered given the risk of a reduced economic life beyond 2011. Furthermore, the Commission is mindful of section 8.11 of the Code which states that an ICB valuation should not normally exceed a DORC valuation although this did not preclude the Commission from considering NT Gas' ODV valuation.

66 Sinclair Knight Mertz (2002), *Depreciation within DORC*, p.5

2.8.3 International best practice

International best practice of pipelines in comparable situations and the impact on the international competitiveness of energy consuming industries (section 8.10(e))

It is important to note that the Code distinguishes between existing and new investment with regard to the value of the asset base. DORC is only relevant to the establishment of the value of the initial capital base of existing covered pipelines. Capital expenditure with respect to new covered pipelines, and new investment on existing covered pipelines, is added to the capital base at actual cost. Comparisons with ongoing investment in overseas jurisdictions have little relevance to the establishment of the initial capital base for existing pipelines covered by the Code. It is the rate of return and incentive mechanisms, and not the valuation methodology of the initial capital base, which are more likely to be the main determinants of future investment.

Clearly the international competitiveness of domestic industries is enhanced by having input costs, such as gas transportation, as low as possible. As capital costs form the bulk of gas transportation tariffs, it follows that the lower the value of the initial capital base the lower will be tariffs to end-users. This argument tends to support an asset valuation based on the lower end of the feasible range of asset valuations, that is DAC. However, the international competitiveness of energy consuming industries is only one of several factors that the regulator is obliged to take into account in establishing the value of the initial capital base. These factors are intended to strike a balance between the interests of the service provider and users.

2.8.4 The basis on which tariffs have been set and reasonable expectations

The basis on which tariffs have been (or appear to have been) set in the past, the economic depreciation of the pipeline and historical returns to the service provider (section 8.10(f)); and

Reasonable expectations of persons under the prior regulatory regime (section 8.10(g))

It is the Commission's view that in the circumstances of the ABDP, it is appropriate to consider section 8.10(f) and section 8.10(g) together given that they closely align due to the arrangements that facilitated the construction of the pipeline.

Section 8.10(f) of the Code provides for the regulator to give consideration to the basis upon which tariffs have been (or appear to have been) set in the past, economic depreciation of the pipeline and historical returns. The Commission considers that the lease payments schedule and the inclusion of two additional cost components, of which it was not previously made aware, can provide a good indication as to the basis upon which tariffs have been set in the past and will be set in the future.

It is the Commission's view that consideration of sections 8.10(f) and (g) relates to contractual issues that are confidential in nature.   Accordingly, the detailed discussion of these issues is contained within Confidential Annexure C.

Wealth transfers or windfall gains

The Commission does not agree with NT Gas' assertion that the Code imposes no obligation on the regulator to consider wealth transfers or 'windfall gains', to either the service provider or users, when setting the ICB. While section 8.10 of the Code does not explicitly refer to windfall gains (or their avoidance), the Commission considers that possible wealth transfers are relevant to the determination of the ICB.

For example, section 8.10(a) of the Code requires the regulator to consider the actual capital cost of assets and the accumulated depreciation already charged to users. Section 8.10(f) also requires the regulator to consider the basis upon which tariffs have been (or appear to have been) set in the past and historical returns to the service provider. Thus, it is implicit that the Commission ought to have regard to past recovery levels when determining an appropriate ICB. Hence, there is a need to ensure that, where possible, wealth transfers are kept to a minimum.

In the context of the ABDP the Commission has been supplied with information that enabled an understanding of the basis of which tariffs have been determined, in the past. The Commission is of the view that the lease schedule provides a sound indication of the accumulated depreciation that has already been recovered by NT Gas. It is the Commission's view therefore that reference tariffs that are cognisant of the lease schedule and other cost factors will result in tariffs that will not produce a windfall gain to the service provider. Further discussion of the depreciation profile is in section 3.3.6. Due to the commercially sensitive nature of the GSA and the lease agreement these issues are more fully discussed in confidential Annexure C.

Section 8.10(g) of the Code requires the regulator to take into account the reasonable expectations of various parties under the regulatory regime that applied prior to the commencement of the Code.

It is the Commission's view that while NT Gas has not been subject to formal regulation, the foundation contracts, lease arrangements and NT Gas binding obligations and contracts which facilitated the construction of the ABDP would have strongly influenced the reasonable expectations of the service provider. It is likely that NT Gas would have the expectation that it recover costs associated with its investments. Furthermore, the Commission considers that based upon information viable to it these agreements influenced the tariff structure that NT Gas has applied, in the past.

In addition, it is also the Commission's view that it would have been the reasonable expectation of the service provider that it could recover investment decisions made outside the lease agreement. Accordingly, the Commission recognises that the recovery of non-pipeline asset investments is appropriate.

It is the Commission's view that in the circumstances of the ABDP both section 8.10(f) and (g) of the Code, in addition to the other relevant provisions, provide a basis upon which the proposed reference tariffs can be assessed. The Commission has had regard to NT Gas' reasonable expectations and the basis upon which tariffs have been set in the past. The Commission has had regard to these considerations in determining the ICB.

More specific consideration regarding sections 8.10(f) and (g) is contained within Confidential Annexure C

2.8.5 Utilisation of the pipeline

Economically efficient utilisation of gas resources (section 8.10(h));

This provision requires the Commission to have regard to a valuation methodology consistent with providing price signals that result in incentives for the efficient development and use of gas resources. This can be achieved by setting tariffs which reflect the true costs of gas transmission services. Economic principles do not provide clear guidance on the valuation of sunk assets from the perspective of economic efficiency, hence, a feasible range of asset values is permitted under the Code.

However, economic principles do suggest that, irrespective of the valuation assigned to sunk costs, these costs should be recovered in a manner that distorts the behaviour of system users and operators as little as possible. In this regard the methodology used to allocate costs to services and users is perhaps of more relevance than the overall valuation of the initial capital base. The subject of cost allocation is considered later in this *Final Decision* in section 3.8.

2.8.6 Comparability against a new competing pipeline

Comparability with the cost structure of a competing pipeline (section 8.10(i));

The Code also requires the regulator to examine is the comparability with the cost structure of new pipelines that may compete with the pipeline in question (for example, a pipeline that may by-pass some or all of the ABDP). As discussed throughout this decision, there is a strong likelihood that the ABDP will become at least partially stranded sometime in the future due to Timor Sea gas coming onshore. While the Timor Sea gas pipeline would compete with the ABDP for the supply of gas into Darwin, it is unclear whether the pipeline would be a represent a comparable cost structure to that of the ABDP.

The capital cost of the proposed Timor Sea gas pipeline, which will link Timor Sea gas reserves with Darwin, is estimated to be around $1.5 billion.[67] However, the nature of the Timor Sea gas pipeline is very different to that of the ABDP. While the specifications of the pipeline are still being finalised, the Timor Sea gas pipeline is expected to be a 36-inch sub-sea pipeline 500km long with a maximum pressure of 790 PJ per year.[68] In addition, the Timor Sea gas pipeline project is still in the planning stage of development and it is difficult to determine what the final capital cost and specifications of the pipeline might be.

Therefore, for the purposes of determining an appropriate ICB for the ABDP, it is difficult to compare the costs of the Timor Sea gas pipeline with the costs of the ABDP. It is also important to note that the Timor Sea gas pipeline does not duplicate the

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67 Northern Territory Government, *Development Outlook – Australia's Northern Territory*, May 2001, p 24.

68 Northern Territory Government, *Development Outlook – Australia's Northern Territory*, May 2001, p 24.

ABDP. The supply of gas for each pipeline is from a different source and the ABDP also supplies other regions of the Northern Territory, in addition to Darwin.

Nevertheless, the construction of the Timor Sea gas pipeline does raise issues for the Commission in its assessment of NT Gas' access arrangement for the ABDP. As discussed earlier, Timor Sea gas being brought onshore has implications for the future cash flows of the ABDP. It also influences the treatment of depreciation on the pipeline going forward (see section 3.3).

2.8.7 Price paid for any asset recently purchased

Commission's consideration of the price paid for any asset recently purchased by the service provider and the circumstances of that purchase (section 8.10(j))

The acquisition of the ABDP occurred as part of a transaction involving a portfolio of assets. The details of the acquisition are considered commercial-in-confidence. The Commission's considerations are therefore contained in Confidential Annexure F.

2.8.8 Advantages and disadvantages of valuation methodologies

The advantages and disadvantages of each valuation methodology applied under paragraphs [8.10] (a), (b) and (c) (section 8.10(d));

The Commission considers the advantages and disadvantages of the proposed ICB approaches determined pursuant to section 8.10(a), (b) and (c) are assessed as part of the evaluation of these methodologies against the section 8.1 criteria.

2.9 Code requirements in relation to the ICB

Section 8.1 provides that the Commission is guided by the objectives for the design of a reference tariff and the reference tariff policy should be designed with a view to achieving a number of specified objectives outlined in section 8.1 of the Code. These objectives are relevant for guiding the Commission's consideration of the factors in section 8.10 of the Code. As the ICB is a crucial element in the consideration of the reference tariffs and reference tariff policy, objectives in determining the ICB for this *Final Decision* include:

s 8.1(a) providing the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the Reference Service over the expected life of the assets used in delivering that Service**;**

(b) replicating the outcome of a competitive market;

(c) ensuring the safe and reliable operation of the Pipeline;

(d) not distorting investment decisions in Pipeline transportation systems or in upstream and downstream industries;

(e) efficiency in the level and structure of the Reference Tariff; and

(f) providing an incentive to the Service Provider to reduce costs and to develop the market for Reference and other Services.

To the extent that any of these objectives conflict in their application to a particular Reference Tariff determination, the Relevant Regulator may determine the manner in which they can best be reconciled or which of them should prevail.

However, section 8.1 includes objectives that may, at times, be in conflict with each other. On these occasions the regulator must determine how the conflict will be reconciled by reference to the factors in section 2.24 of the Code. Section 2.24 states:

> ... In assessing a proposed Access Arrangement, the Relevant Regulator must take the following into account:
>
> (a) the Service Provider’s legitimate business interests and investment in the Covered Pipeline;
>
> (b) firm and binding contractual obligations of the Service Provider or other persons (or both) already using the Covered Pipeline;
>
> (c) the operational and technical requirements necessary for the safe and reliable operation of the Covered Pipeline;
>
> (d) the economically efficient operation of the Covered Pipeline;
>
> (e) the public interest, including the public interest in having competition in markets (whether or not in Australia);
>
> (f) the interests of Users and Prospective Users;
>
> (g) any other matters that the Relevant Regulator considers are relevant.

The recent Western Australian Supreme Court Epic decision provides guidance as to the appropriate application of sections 8.1 and 2.24 by a regulator. The Court stated:

> ... The last paragraph of s8.1 recognises that the objectives of (a) to (f) in s8.1 may conflict in their application to a particular reference tariff determination, in which event the Regulator may determine the manner in which they can best be reconciled or which of them should prevail. Contrary to the submissions of the Regulator and Alinta, the discretionary task of seeking to reconcile conflicting objectives within s8.1, and even more significantly of determining which of them should prevail, cannot be decided by reference to s8.1 itself. Of necessity, the Regulator must have guidance outside of s8.1 in exercising those discretions. In this regard it appears from the structure and provisions of the Code that have been canvassed that s2.24(a) to (g) would most naturally guide the Regulator in the exercise of these discretions, and was intended to do so. That is, in exercising the discretions contemplated by the last paragraph of s8.1 the Regulator should take into account the factors in s2.24(a) to (g).[69]

In view of the Commission’s obligations pursuant to the Code, it will consider the section 8.1 criteria and then the section 2.24 criteria as part of its *Final Decision* deliberations. These objectives are relevant for guiding the Commission’s consideration of the factors in section 8.10 of the Code. As the ICB is a crucial element in the consideration of the reference tariffs and reference tariff policy, the Commission has assessed the possible ICB valuations against the section 8.1 objectives in determining the ICB for this *Final Decision*.

Section 8.1 provides that Commission’s considerations of the price paid for any asset recently purchased by the service provider and the circumstances of that purchase (section 8.10(j)). Due to the commercially sensitive nature of this issues and related

[69] Re Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231 at paragraph 85.

matters, the Commission's considerations under section 8.10(j) are considered in confidential Annexure F.

2.10 Commission's considerations of 8.1 factors in relation to the ICB

In determining the ICB for this *Final Decision*, the Commission has assessed the possible ICB valuations against the criteria of section 8.1 of the Code. Due to the commercially sensitive nature of material relating to the reasonable expectations and legitimate interests of the service provider under section 8.10(g) and (j) of the Code, the Commission considers these issues in Confidential Annexure C.

In considering the proposed ICB for the ABDP, the Commission is of the view that section 8.1 criteria:

(c) Ensuring the safe and reliable operation of the pipeline;

(e) Efficiency in the level and structure of the Reference tariff; and

(f) Providing an incentive to the Service Provider to reduce costs and to develop the market for Reference and other Services

form part of the broader assessment of the of the reference tariff and reference tariff policy, rather than the ICB alone. It is for this reason that consideration of sections 8.1(c), (e) and (f) of the Code are considered in the context of the reference tariff and reference tariff policy, in chapter three.

s.8.1(a) providing the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the Reference Service over the expected life of the assets used in delivering that Service

Optimised Deprival Valuation

The Commission has sought to provide NT Gas with the opportunity to earn a stream of revenue that covers the efficient costs associated with the provision of reference services by the ABDP in the context of potentially reduced utilisation or the possible risk of stranding after 2011. It is the Commission's view that given the potentially limited economic life of the ABDP, that the use of the ODV value provides a sound basis for the determination of the ICB in these circumstances.

The Commission has sought to ensure that all costs associated with the efficient delivery of the reference services are included in the capital base. For that reason, a past investment in the pipeline which cannot be assessed in the public domain is discussed in more detail in Confidential Annexure C. That capital component is to be included as part of the ICB. This capital investment has enabled and will continue to facilitate the efficient provision of reference services into the future. The Commission has determined the NPV of this capital outlay and capitalised it into the ICB.

The Commission has also sought to ensure that non-pipeline investment in the pipeline can be recovered. The Commission has applied a DORC valuation to the pipeline's non-pipeline assets to produce an optimal valuation for these assets. It is the Commission's view that the non-pipeline assets have contributed to and will continue to enable the efficient provision of reference services. Accordingly, a return on and return of capital should be provided for, this is achieved by the including the DORC valuation of these assets in the ICB.

The Commission has taken into account the requirements of section 8.11 of the Code and determined an ICB valuation that is with the range established by the application of DORC ($304.5m to $373m) and DAC ($186m) and provides for the efficient provision of reference services over the likely remaining life of the ABDP.

The Commission believes this valuation is appropriate for determining reference tariffs and reference tariff policy with a view to achieving the objective in section 8.1(a) of the Code.

Depreciated Actual Cost and Draft Decision ICB

The Commission is guided by section 8.11 of the Code in choosing not to determine an ICB based upon the *Draft Decision* valuation of $176.3m, as this valuation is outside the range of DORC ($304.5m - $373.7m) and DAC ($186m) determined as part of this *Final Decision*, although the Commission notes that is it not prevented from considering valuations outside of this range depending on the circumstances. The Commission is of the view that the *Draft Decision* ICB valuation and the DAC valuation would be unlikely to ensure the efficient provision of reference services for the ABDP, specifically as they exclude a capital cost, which is necessary to ensure the provision of reference services. The *Draft Decision* ICB or the DAC would not provide for the recovery of efficient costs associated with the provisions of gas transmission services.

The Commission is also of the view that an ICB based upon either of the DAC valuation of $186m or the *Draft Decision* ICB of $176.3m would be contrary to achieving the objective in section 8.1(a) of the Code.

Residual Valuation

The Commission has also given consideration to the residual valuation as a possible valuation for the ICB. However, again the Commission is mindful of section 8.11 of the Code which provides that the ICB valuation should not normally fall outside the range of DAC $179.3m and DORC ($304.5 – $373.7m). The Residual valuation exceeds the range that an ICB should normally fall within. NT Gas has not asserted that an ICB based upon the residual valuation is in their legitimate interests, noting that the use of a residual value approach produced a valuation above DORC and suggested that the DORC methodology was more appropriate.

For these reasons, the Commission is of the view that an ICB based upon a residual value valuation of the pipeline would be contrary to achieving the objective in section 8.1(a) of the Code.

Purchase Price

Due to the commercially sensitive nature of the purchase price of the ABDP, the Commission considers this matter in more detail in Confidential Annexure F. Based upon these considerations in Confidential Annexure F, the Commission is of the view that an ICB based upon the purchase price valuation of the pipeline would be contrary to achieving the objective in section 8.1(a) of the Code.

s.8.1(b) replicating the outcome of a competitive market;

It is the Commission's view that an ICB based upon its ODV approach would produce an outcome that is consistent with a workably competitive market by providing the service provider an opportunity to earn a return of and return on capital associated with the efficient provision of reference services until 2011. Given the risk of the ABDP being stranded by 2011 or it having diminished usage after 2011, the Commission is of the view that an ICB in excess of that valuation would potentially raise the prospect that the ABDP could be bypassed by a pipeline providing cheaper reference services.

In the circumstances of the ABDP, the ODV methodology provides an alternate valuation approach that is consistent with that which would occur in a workably competitive market. In such a market the service provider would seek to recover its capital base by the potential stranding date, it could not do this if it were bypassed by a new entrant.

An ICB valuation based upon the DORC approach within the range of $304.5m to $373.7m could provide an incentive to by-pass the ABDP prior to 2011. The Commission is also of the view that as both the residual value and NT Gas' ODV valuation exceed the estimated DORC range, these valuations could expose the ABDP to the risk of bypass or stranding.

The Commission is of the view that its ODV is consistent with section 8.1(b) and section 8.1(d), which is discussed further below.

8.1(d) not distorting investment decisions in Pipeline transportation systems or in upstream or downstream industries;

The Commission understands that investment in the ABDP was made possible by the lease agreement, the GSA and an additional capital component (which is discussed more in Confidential Annexure C) and additional investment since the construction of the ABDP. The Commission is mindful that its assessment of the ICB is not constrained to forward looking costs only. To do so would potentially result in the under-recovery of past prudent and commercially sound investment decisions.

It is the Commission's view that its proposed ICB is unlikely to distort investment in the ABDP as it provides for the recovery of efficient capital base costs, as expressed through the lease agreement, the GSA and other investment in the pipeline since the construction of the pipeline.

Depreciated Actual Cost and Draft Decision ICB

The Commission is of the view that an ICB based upon DAC or the *Draft Decision* ICB would potentially distort investment in the pipeline through under-recovery of total capital investment in the ABDP. Specifically, these ICB valuations do not include the capital component (discussed in further detail in Confidential Annexure C) and therefore place at risk the continued capacity for NT Gas to meet its obligations. The Commission was only informed of this additional capital component following the release of the *Draft Decision*.

Purchase Price

Due to the commercially sensitive nature of the purchase price of the ABDP, the Commission considers this matter in more detail in Confidential Annexure F.

2.11 The Commission's consideration of 2.24 factors

The Commission is of the view that the proposed ICB approach is appropriate for determining reference tariffs and reference tariff policy in accordance with the objectives in section 8.1 of the Code. The Code requires the Commission to also take into account matters set out in section 2.24 of the Code in its decision making processes.

Accordingly, the Commission has considered, *inter alia*, the legitimate interests of the service provider and the binding contractual obligations that facilitated the construction of the pipeline.

> *2.24(a) the Service Provider's legitimate business interests in the Covered Pipeline;*
>
> *2.24(b) firm and binding contractual obligations of the Service provider or other persons (or both) already using the Covered Pipeline:*

It is the Commission's view that the legitimate business interests of NT Gas are served by being able to meet its contractual obligations for the ABDP. The proposed ICB achieves this outcome, consistent with section 2.24(a) of the Code, by providing for the recovery of the lease agreement and GSA capital costs.

The Commission is of the view that the proposed ICB enables NT Gas to meet its binding contractual obligations in relation to capital costs as represented by the lease, the GSA and subsequent investment in the pipeline. As mentioned previously, these agreements were necessary for the construction of the ABDP. It is the Commission's view that the protection of these binding agreements is in the broader public interest given they facilitated the construction of the ABDP.

In response to the *Draft Decision*, interested parties such as Woodside, Shell and NTPG considered that the Commission's ICB valuation of $176.2m was too high. Furthermore, and in response to the *Draft Decision*, Nabalco expressed its support for the use of DAC ($186m) as the ICB valuation methodology. It is the Commission's view that the DAC and the *Draft Decision* ICB would place the GSA and the lease agreement at risk by being at a level that would under-recover total capital costs. Furthermore, these valuations do not include provision for the recovery of an additional capital cost that the Commission became aware of after the *Draft Decision*.

This *Final Decision* ICB provides for the recovery of all capital costs.

> *2.24(c) the operational and technical requirements necessary for the safe and reliable operation of the Covered Pipeline.*

The Commission has been mindful to ensure that the ICB determination does not impinge upon ABDP's ability to ensure the safe and reliable operation of the pipeline. It is the Commission's view that the proposed ICB satisfies this requirement by providing for the recovery of relevant capital costs. The Commission therefore is of the view that its proposed ICB approach is consistent with section 2.24(c) of the Code.

2.24(d) the economically efficient operation of the pipeline;

It is the Commission's view that the proposed ICB provides for the recovery of efficient capital costs associated with the operation of the pipeline, given the risk of stranding after 2011. The proposed ICB allows for the recovery of pertinent capital costs by 2011 while alternate valuation methodologies would have resulted in the over or under recovery of such costs. The Commission is therefore of the view that its ICB valuation recognises ABDP's operating environment and provides NT Gas with incentives for the economically efficient operation of the pipeline.

2.24(e) the public interest, including the public interest in having competition in markets (whether or not in Australia);

It is the Commission's view that the broader public interest under s.2.24(e), including the public interest in having competition in markets would not be served by determining an asset base that did not recognise the existing obligations of NT Gas

The broader NT community has benefited from the construction of the ABDP due to it facilitating the:

- Development of the NT's indigenous gas reserves;
- Creation a NT gas market;
- Reduction in the cost of electricity to NT consumers;
- Provision substantial NT-based employment and industry opportunities; and
- Development of the McArthur River, Cosmo Howley and Woodcutters mines[70].

The GSA and the lease agreements form the cornerstone of the ABDP financial structure, and without them it is unlikely the pipeline would have been built. It is the Commission's view that the public interest would be served, under section 2.24(e) of the Code, by the continued operation of these agreements given the significant role they have played in allowing for the construction of the pipeline and its related economic and social benefits to the NT.

2.24(f) the interests of users and prospective users;

In assessing the section 8.1 objectives the Commission has also been mindful to consider the interests of users and prospective users of the ABDP. It is the Commission's view that its proposed ICB is meaningful in the context of the ABDP and its potentially reduced utilisation after 2011. The proposed ICB provides for the recovery of efficient capital costs, consistent with section 8.1 of the Code, associated with the provision of reference services by the time that the ABDP may experience a

[70] NT and PWC submission to the ACCC in response to the *Draft Decision*, 4 October 2001, p.4

diminishing demand for its services. The capital costs of the ICB represent those necessary to supply reference services and strike a balance between users and the recovery of capital costs that enabled the construction of the ABDP.

2.12 Deferred tax liability

In this *Final Decision*, the Commission has determined that there will not be an adjustment for the tax liability (DTL) in the ABDP ICB valuation.

2.13 Conclusion

The Commission has concluded that the possible risk of the ABDP facing a reduced economic life beyond 2011 remains and that the application of DORC to the ABDP is unlikely to result in an appropriate ICB valuation in those circumstances and would be contrary to achieving the objectives in section 8.1 and the criteria in section 2.24 of the Code. It is also for these reasons that the Commission has rejected the other proposed ICB valuations.

Given the possibility of a reduced economic life after 2011 the Commission has determined that an Optimised Deprival based valuation provides the most appropriate asset base compared other relevant methodologies. The proposed ICB is drawn directly from the lease agreement and other relevant non-leased capital costs. It reflects the commercial arrangements that underpinned the GSA and is assessed as being consistent with the reasonable expectations of the Service Provider.

This approach has produced an ICB of $228.5m as at 1 July 2001. It is the Commission's view, given the unique circumstances of the ABDP, that this methodology provides the most appropriate valuation of the pipeline's ICB in accordance with section 8.1 and 2.24 of the Code.

FDA2.1

In order for NT Gas' access arrangement for the ABDP to be approved, the value of the initial capital base must be adjusted to the value derived by the Commission of $228.5m as at 1 July 2001.

3. Reference tariff elements

3.1 Reference tariff methodology

Section 8 of the Code sets out the general objectives for a reference tariff and certain factors about which the relevant regulator must be satisfied before the regulator may approve reference tariffs and the reference tariff policy. The general principles are contained in sections 8.1 and 8.2 of the Code. Their application to NT Gas' proposed access arrangement are discussed in section 3.9 of this *Final Decision*, after consideration of the parameters making up the revenue requirement and tariff.

Section 8.4 of the Code permits a choice of three methodologies for determining the total revenue:

Cost of service: where total revenue is set to recover costs. These costs are calculated on the basis of:

- a return (rate of return) on the value of the capital assets that form the covered pipeline (capital base);
- depreciation of the capital base (depreciation); and
- the operating, maintenance and other non-capital costs (non-capital costs) incurred in providing all services over the covered pipeline.

The rate of return is set to provide a return commensurate with prevailing conditions in the market for funds and the risk involved in delivering the reference services (sections 8.30 and 8.31 of the Code).

IRR: where total revenue is set to provide an acceptable internal rate of return (IRR) for the covered pipeline on the basis of forecast costs and sales, subject to the principles set out in sections 8.30 and 8.31 of the Code.

NPV: where total revenue is set to deliver a net present value (NPV) for the covered pipeline (on the basis of forecast costs and sales) equal to zero, using a discount rate that would yield a return consistent with sections 8.30 and 8.31 of the Code.

While these methodologies provide different ways of assessing the total revenue requirement, their outcomes should be consistent. For example, it is possible to express any NPV calculation in terms of a cost of service calculation by the choice of an appropriate depreciation schedule. In addition, other methodologies (such as a method that provides a real rate of return on an inflation-indexed capital base) are acceptable under section 8.5 of the Code provided they can be translated into one of these forms.

NT Gas proposed a cost of service methodology.[71] This methodology is consistent with the Code.

As part of the access arrangement and access arrangement information, NT Gas proposed a three zone pricing scheme. NT Gas has advised the Commission that the pipeline is currently fully contracted and there is no firm capacity available for third party access.[72]

3.2 New facilities investment and capital redundancy

3.2.1 Code requirements

The Code (section 8.9) states that the capital base at the commencement of each access arrangement period subsequent to the first is determined as:

(a) the Capital Base at the start of the immediately preceding Access Arrangement Period; plus

(b) the New Facilities Investment or Recoverable Portion in the immediately preceding Access Arrangement Period; less

(c) Depreciation for the immediately preceding Access Arrangement Period; less

(d) Redundant Capital identified prior to the commencement of that Access Arrangement Period.

This leads to the issues of how capital expenditure and capital redundancies are to be treated under an access arrangement for the present period. These issues are the subject of this section.

New facilities investment

The Code (sections 8.15 and 8.16) allows for the capital base to be increased to recognise additional capital costs incurred in constructing new facilities for the purpose of providing services. The amount of the increase is the actual capital cost, provided the investment is prudent in terms of efficiency, in accordance with accepted good industry practice and is designed to achieve the lowest sustainable cost of delivering services.

Unless the incremental revenue is expected to exceed the cost of the investment, the service provider (and/or users) must satisfy the regulator that the new facility has system wide benefits justifying higher tariffs for all users. Alternatively, the service provider must show that the new facility is necessary to maintain the safety, integrity or contracted capacity of services.

Under sections 8.18 and 8.19 of the Code a service provider may also undertake new facilities investment if the foregoing criteria are not met. To the extent that an

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71 Access Arrangement Information, p. 5.

72 Access Arrangement Information, p.2.

investment does not meet the section 8.16 criteria or is speculative in character the augmentation of the capital base needs to be correspondingly reduced.[73]

Reference tariffs may be determined on the basis of forecast investment during the access arrangement period provided that such investment is reasonably expected to pass the requirements noted above when the investment occurs (section 8.20). However, the inclusion of forecast investment does not imply that the section 8.16 criteria have been satisfied. The regulator may reserve its judgment until the investment is undertaken or until the next review. The Code (section 8.22) also provides that the reference tariff policy should specify how discrepancies between forecast and actual investment are to be reflected in the capital base at the commencement of the next regulatory period (so as to meet the objectives of section 8.1 of the Code). Alternatively, the regulator may determine how the expenditure will be treated for the purpose of section 8.9 (changes to the capital base) at the time the regulator considers revisions to an access arrangement.

Capital redundancy

Section 8.27 of the Code allows a reference tariff policy to include (and the regulator may require that it include) a mechanism that will remove redundant capital from the capital base. Such an adjustment is to occur at the commencement of the next access arrangement period so as to:

- ensure that assets which cease to contribute to the delivery of services are not reflected in the capital base; and
- share costs associated with a decline in sales volume between the service provider and users.

Before approving such a mechanism, the regulator must consider the potential uncertainty such a mechanism would cause and the effect that uncertainty would have on the service provider, users and prospective users.

Where redundant assets subsequently contribute to or enhance the provision of services, the Code (section 8.28) allows the assets to be added back to the capital base as if they were new facilities investment subject to the associated criteria noted earlier in this section.

While the Code permits a reference tariff policy to include a mechanism to subtract redundant capital from the capital base, it also allows for other mechanisms that have the same effect on reference tariffs while not reducing the capital base (section 8.29 of the Code).

73 That part of the investment which is of a speculative nature is held in the speculative investment fund and may be added to the asset base at a later date when it meets the necessary criteria.

3.2.2 NT Gas' proposal

New facilities investment

As permitted by section 8.18 of the Code, section 4.4 of NT Gas' reference tariff policy states that 'NT Gas may undertake New Facilities Investment that does not satisfy the requirements of the Code for inclusion in the Capital Base'.[74]

In addition, the policy states that the speculative investment fund (the balance after deducting the recoverable portion of the new facilities investment), may subsequently be added to the capital base. This can occur if the type and volume of services provided, which use the increase in capacity attributable to the new facility, change such that any part of the speculative investment fund would then satisfy the requirements of the Code for inclusion in the Capital Base.[75]

In accordance with section 8.22 of the Code, the reference tariff policy states that:

> … for the purposes of calculating the capital base at the commencement of the subsequent Access Arrangement Period, where the actual cost of New Facilities differs from the forecast New Facilities Investment on which the Capital Base was determined, the New Facilities Investment will be included at actual cost.[76]

NT Gas has disaggregated its new facilities investment into three components for this access arrangement period:

- capacity expansion – capital required to expand the capacity of the ABDP to meet demands both within the Access Arrangement Period and beyond;

- system replacement – capital required to maintain the integrity of the ABDP which would include items such as replacement of instrumentation (eg metering, telemetry remote terminal units etc), pipeline hardware (eg pipes, meters valves, regulators and fittings etc), site capital improvements (eg fencing, security etc), and specialised major spares; and

- non-pipeline system expenditure – capital required for replacement of items such as vehicles and computer equipment.[77]

Subsequent to the *Draft Decision*, NT Gas submitted a revised capital expenditure program, consistent with the 10 year access arrangement period, which is set out in Table 3.1.

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[74] Access Arrangement, p. 15.

[75] Access Arrangement, p. 15.

[76] Access Arrangement, p. 15.

[77] Access Arrangement Information, p. 21.

Table 3.1: Estimated Capital Expenditure ($m)

Year Ending 30 June	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Expansion Capital	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Replacement Capital	0.02	2.51	0.07	0.00	0.07	2.39	0.08	0.00	0.08	0.00
Non-System Capital	0.36	0.49	1.55	0.52	0.53	0.82	0.56	0.57	0.58	0.60
Total	**0.38**	**3.00**	**1.62**	**0.52**	**0.60**	**3.21**	**0.63**	**0.57**	**0.67**	**0.60**
Original Submission[(a)]	1.02	0.80	2.82	-	-	-	-	-	-	-
Variance	**(0.64)**	**2.20**	**(1.2)**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Source: Facsimile from Agility, 5 June p.2 and 11 June 2002, p.3

Note: (a) capital expenditure figures submitted in NT Gas' original access arrangement submission on 25 June 1999.

The above table indicates that NT Gas has revised up its forecast capital expenditure in 2003 due the deferral of SCADA upgrade and projected upgrades for filters at Darwin City Gates and Pine Creek[78]. Additionally, NT Gas proposes to defer a major lateral upgrade previously scheduled for 2004 until 2007, this reduction has been offset by other capital expenditure planned for 2004 but would otherwise have occurred in 2002[79].

NT Gas stated that the proposed expenditure represents best estimates and is required to maintain either the safety and integrity of the ABDP or its services to the satisfaction of Code requirements.[80]

Capital redundancy

The reference tariff policy makes no comment on the treatment of redundant assets. NT Gas stated that there is currently no redundant capital in the ABDP.[81]

3.2.3 Commission's *Draft Decision*

The Commission proposed the following amendments to NT Gas' access arrangement:

Proposed Amendment A2.2

In order for NT Gas' access arrangement for the ABDP to be approved, clause 4 of section 4 of the access arrangement (the reference tariff policy) must state that new facilities investment that does not satisfy the requirements of section 8.16 of the Code

78 Facsimile from Agility to the Commission, 5 June 2002, p.2.

79 Facsimile from Agility to the Commission, 5 June 2002, p.2.

80 Access Arrangement Information, p. 21.

81 Letter from Agility to the Commission, 7 December 2000.

may be undertaken by NT Gas. However, only that portion of the investment that satisfies section 8.16 of the Code may be included in the capital base.

In order for NT Gas' access arrangement for the ABDP to be approved, clause 6 of section 4 of the access arrangement must be amended to clearly specify that any new facilities investment must meet the requirements of section 8.16 of the Code before it can be included in the capital base.

Proposed Amendment A2.3

In order for NT Gas' access arrangement for the ABDP to be approved, the reference tariff policy must be amended to allow the Commission, at the commencement of the subsequent access arrangement period, to review, and if necessary adjust, the asset base for wholly or partially redundant assets, within the meaning of section 8.27 of the Code.

3.2.4 Submissions by interested parties

NTPG disputed the proposed capital expenditure forecasts provided by NT Gas as they did not allow for additional compression of the pipeline so as to ensure the sale of the reference service on a non-interruptible basis during the access arrangement period. NTPG stated that a prudent operator would allow for this to provide scope to grow the market by sale of the reference service.[82]

3.2.5 NT Gas' response to the *Draft Decision*

New facilities investment

NT Gas agreed that clause 6 of the reference tariff policy appeared to suggest that all new facilities investment would automatically be included in the capital base. NT Gas stated that this was unintended and it would submit proposed amendments to rectify the clause.[83]

NT Gas considered that the Commission's proposed amendment to clause 4 of the reference tariff policy was unnecessary, as the Code already specifies the manner in which the capital base will be determined. NT Gas further stated:

> To require inclusion of specific Code provisions in an access arrangement blurs the line between the operation of the Code and the role of the access arrangement. It could also lead to significant ambiguity or uncertainty if, after the date of the access arrangement, the relevant Code provision is amended.[84]

Additionally, NT Gas believed that the rationale for the amendment – to provide clarification to users regarding the determination of the capital base in subsequent regulatory periods – assumes that such persons are unable to locate and interpret the Code. NT Gas contended that this was clearly not the case.[85]

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82 NTPG submission, 2 August 2001, pp. 2–4.

83 NT Gas submission, 14 November 2001, p. 22.

84 NT Gas submission, 14 November 2001, p. 22.

85 NT Gas submission, 14 November 2001, p. 22.

Capital redundancy

NT Gas stated that it would not object to the proposed amendment if it were accompanied by a commensurate adjustment to the allowed rate of return for the pipeline.[86]

NT Gas considered that the risk presented by the proposed amendment is the risk that at expiry of the access arrangement period, the Commission will remove an amount from the capital base. NT Gas claimed that this was a different risk from the risk that there will be reduced pipeline utilisation from 2011.[87]

3.2.6 Commission's considerations

New facilities investment

Clause 4.4 of NT Gas' access arrangement states that 'NT Gas may undertake new facilities investment that does not satisfy the requirements of the Code for inclusion in the capital base'.[88]

The Commission is concerned that clause 4.4 implies that speculative investment undertaken by NT Gas' may be included in the capital base irrespective of whether or not it satisfies section 8.16 of the Code. While it is recognised that the Code would take precedence over the access arrangement in the event of a conflict, the Commission considers that clause 4.4 may mislead or cause confusion for a prospective user and as such would be contrary to the interests of third parties under section 2.24(f) of the Code.

The Commission notes NT Gas' argument that a future Code change could lead to ambiguity or uncertainty regarding the application of the clause. This could potentially be the case if the Commission were requiring NT Gas to incorporate the requirements set out in section 8.16 in their entirety. However, the Commission is only requiring that reference be made to a specific section of the Code. This does not prevent changes to section 8.16 of the Code from applying under the access arrangement after it has been approved.

While the Commission does not consider it likely that the numbering of the clause would be changed, in the event that this did occur, the Code would still take precedence and/or revisions could be submitted to the access arrangement. Nevertheless, the Commission recognises NT Gas' concerns and has modified its proposed amendment to refer to the 'Code requirements' rather than specifically to section 8.16. The Commission considers that the effect of the amendment remains unchanged and that it will take into account the interests of users and prospective users under section 2.24(f) of the Code

86 NT Gas submission, 14 November 2001, p. 23.

87 NT Gas submission, 14 November 2001, p. 23.

88 Access Arrangement, p 15.

Forecast capital expenditure

As permitted by section 8.20 of the Code, NT Gas determined tariffs on the basis of forecast capital expenditure. However, section 8.20 states that this can only occur where the forecast expenditure is reasonably expected to pass the requirements in section 8.16. Based on the information available, it appears that the capital expenditure forecast by NT Gas would meet the criteria in section 8.16 of the Code. However, pursuant to section 8.21 of the Code, this does not imply that the Commission considers that the section 8.16 criteria are met. An assessment of the actual capital costs incurred will be made by the Commission at the time of the review of the access arrangement.

Adjustment to capital base for actual capital expenditure

Section 8.22 of the Code requires either the regulator to determine or the reference tariff policy to describe whether (and how) the capital base at the commencement of the next access arrangement period should be adjusted if actual capital expenditure differs from forecast capital expenditure. In this instance, NT Gas included a statement in the reference tariff policy that new facilities investment will be included at actual cost (section 4.6). While this statement satisfies the requirement of section 8.22 of the Code, the Commission was concerned that the clause appeared to imply *all* new facilities investment would automatically be included at actual cost regardless of whether it satisfied section 8.16 of the Code.

As noted in its submission, NT Gas agreed that the clause may lead to misinterpretation and signalled its intention to submit proposed amendments to rectify the clause.

Amendment FDA3.1

In order for NT Gas' access arrangement for the ABDP to be approved, clause 4 of section 4 of the access arrangement must state that new facilities investment that does not satisfy the requirements of the Code may be undertaken by NT Gas. However, only that portion of the investment that satisfies the requirements of the Code may be included in the capital base.

In order for NT Gas' access arrangement for the ABDP to be approved, clause 6 of section 4 of the access arrangement must be amended to clearly specify that any new facilities investment must meet the requirements of the Code before it can be included in the capital base.

Allowance for an additional compressor

In its submission, NTPG requested that an allowance for an additional compressor be included in NT Gas' capital expenditure.

Given the ABDP's risk of stranding, it is understandable that NT Gas may be particularly cautious when considering the expansion of the pipeline in excess of contracted capacity. NT Gas would also need to be reasonably assured that the investment would meet section 8.16 of the Code for inclusion in the asset base at the end of the access arrangement period. The Commission considers it contrary to the legitimate interests of the service provider to require the funding of an additional compressor, at this stage, the legitimate interests of the service provider under section

2.24(a) of the Code may not be served by the construction of an additional compressor if the recovery of the investment remains uncertain due to the risk of stranding sometime after 2011.

Except in the instance of an arbitration,[89] the decision to engage in further investment is ultimately the service providers. As a service provider is generally acknowledged to be better informed and experienced than the regulator to make such an investment decision, the Commission is reluctant to interfere without good reason for doing so.

In addition, the inclusion of an allowance for an additional compressor in NT Gas' forecast capital expenditure does not guarantee that the investment will be undertaken. Nor does the exclusion of an appropriate allowance prohibit NT Gas from engaging in speculative investment and constructing an additional compressor.

The option also exists for a third party to fund the expansion of the ABDP. The Commission considers that this, and other options outlined above provide flexibility for both NT Gas and existing or new users in determining the most appropriate means for increasing the capacity of a pipeline. By not limiting these options, the Commission is ensuring that both legitimate interest of users and potential users under section 2.24(f) and the legitimate interests of the service provider (section 2.24(a)) are not hindered. The Commission would only seek to impose a limitation on this flexibility where a failure to do so would cause a detriment to the service provider, users or the public interest.

The Commission does not consider it necessary to include an allowance for an additional compressor in NT Gas' capital expenditure because of the implications for the legitimate interests of the service provider and the option for a third party to fund a compressor should they require it.

Capital redundancy

NT Gas has not included in its reference tariff policy a mechanism that will remove redundant capital from the capital base at the start of the subsequent access arrangement period, as provided for by section 8.27 of the Code. The Commission considers that such a mechanism is needed in order to ensure that users do not pay for assets that have ceased, or have substantially ceased, to contribute to the delivery of services. Accordingly, the Commission, pursuant to section 8.27 of the Code, requires that a mechanism dealing with redundant capital be included in the ABDP reference tariff policy.

Section 8.27 of the Code also states that the regulator must take into account any uncertainty caused by the inclusion of a redundant capital policy and the possible effects that uncertainty would have on the service provider, users and prospective users. It further states that if such a mechanism is included, the rate of return and the economic life of the assets should take account of the resulting risk (and cost) to the service provider of a fall in the revenue received from the sales of its services.

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89 Under Section 6.8(b) of the Code, the Arbitrator may require the service provider to install new facilities to increase the capacity of the pipeline.

The issue of perceived regulatory risk associated with the removal of redundant capital was discussed at length in the *Draft Regulatory Principles*. It was noted that in a competitive market, firms have to face and manage the risk of stranded asset cost due to competition and technological advancement and where assets are stranded as a result of poor investment decisions or adverse circumstances, a full commercial return on the investment will not be achieved. While there was no desire to increase uncertainty for the service provider, it was also not considered appropriate to shield natural monopolies totally from business risk. The risk of redundancy or stranding was also recognised as an incentive to the firm to take more care when making initial investments.[90]

The *Draft Regulatory Principles* further stated:

> …the mechanisms in place to provide for faster return of capital (depreciation) on assets at risk, places the means and decision to significantly diminish any possible commercial loss in the hands of the TNSP. To the extent that a residual risk of loss remain, the beta factor used to develop the regulatory rate of return already reflects many elements of commercial risk via the benchmark basis for its determination. If the anticipatory write-down option is not exercised the TNSP has made a choice to enjoy the fruits of the regulatory rate of return on assets at risk against the capital loss associated with by-pass.[91]

Given that the service provider is in a good position to identify assets at risk of stranding well in advance of the threat actually materialising and can seek compensation through accelerated depreciation, the need for the immediate write-off of assets is removed. This approach ensures a full return of capital and does not represent a financial loss to the service provider. Having the flexibility to pursue such an approach removes much of the risk associated with capital becoming redundant or stranded.

Notwithstanding the above arguments, as discussed in section 3.3, the majority of the ABDP's assets[92] are already subject to the risk of stranding, which is compensated for through the application of accelerated depreciation. It is therefore the Commission's view that the proposed reference tariff policy and reference tariffs incorporate a mechanism to protect the legitimate interests and investment of NT Gas under section 2.24(a) of the Code by allowing for the recovery of a substantial portion of the asset base by 2011, the date after which a reduced usage and possibly stranding may occur. Given the application of accelerated depreciation, only a minimal amount of remaining capital would be subject to the risk of removal from the capital base.

The inclusion of a capital redundancy clause in the access arrangement is not designed to penalise the service provider for investments undertaken in good faith, which have proved over time to be poor. Rather, the clause is designed to allow for the removal of inefficient investment, that is, where it is considered unreasonable to require users to pay for that investment. This is comparable to a competitive market, where a firm would be unable to recover the costs of inefficient or imprudent investments from

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90 ACCC, *Draft Statement of Principles for the regulation of Transmission Revenues*, 27 May 1999, p. 52.

91 ACCC, *Draft Statement of Principles for the regulation of Transmission Revenues*, 27 May 1999, pp. 52 – 53.

92 The ABDP's pipeline assets (including native title allowance (2.5%) and interest during construction (5.2%)) represent 87.2% of the total ORC value.

customers. It is the Commission's view that the specific inclusion of a redundant capital policy would be in accord with the requirements of section 2.24 (f) of the Code. A redundant capital policy is in the interests of users and perspective users by ensuring that the reference tariff policy and reference tariffs reflect prudent investment decisions. Furthermore, a reference tariff that incorporated imprudent investment might also be contrary to the economically efficient operation of the pipeline under section 2.24(d) of the Code.

Section 8.28 of the Code also provides that if any redundant capital subsequently contributes to the delivery of services the assets may be treated as new facilities investment having a value equal to the redundant capital value carried forward at the rate of return from the time the capital was removed. This protects the legitimate interests of the service provider by permitting the recovery of investment decisions that subsequently prove to be prudent and is therefore consistent with section 2.24(a) of the Code.

Further, the Commission also considers that the possible risks to revenues due to the inclusion of the redundant capital policy are minimal and will therefore not be contrary to the legitimate interests of NT Gas under section 2.24(a) of the Code. Given that the ABDP is fully contracted until 2011, barring a force majure event, revenues are virtually guaranteed under the foundation contract. Therefore, the revenue risk faced by NT Gas due to the inclusion of a redundant capital policy is negligible.

Therefore, the Commission does not consider that placing a redundant capital policy in NT Gas' access arrangement materially increases uncertainty for the service provider/users or requires an adjustment to the required rate of return on the pipeline.

Amendment FDA3.2

In order for NT Gas' access arrangement for the ABDP to be approved, the reference tariff policy must be amended to allow the Commission at the commencement of the subsequent access arrangement period to review, and if necessary adjust, the asset base for wholly or partially redundant assets within the meaning of the Code.

3.3 Depreciation and inflation

3.3.1 Code requirements

Sections 8.32 and 8.33 of the Code set out the principles for calculating depreciation for the purposes of determining a reference tariff. In brief, the depreciation schedule should meet the following principles:

- It should result in the reference tariff changing over time consistently with the efficient growth of the market for the services provided.
- Depreciation should occur over the economic life of each asset or group of assets, with progressive adjustments to the maximum extent that is reasonable to reflect changes in expected economic lives.

- Subject to the capital redundancy provisions (section 8.27), an asset is to be depreciated only once. Thus the total accumulated depreciation of an asset will not exceed the value of the asset at the time the asset or group of assets was first incorporated in the capital base.

Section 8.5 permits any methodology to be used to determine the total revenue requirement, provided it can be expressed in terms of one of the methodologies described in section 8.4 of the Code.

Section 8.5A allows any of the methodologies described in section 8.4 or permitted under section 8.5 to be applied on either a nominal basis, a real basis or any other basis which deals with the effect of inflation, provided that it is approved by the regulator and applied consistently in determining total revenue.

3.3.2 NT Gas' proposal

Depreciation

NT Gas proposed the use of a 'kinked straight line' depreciation methodology for the accelerated depreciation of its transmission pipeline assets and a standard straight line methodology for its remaining assets (ie compressor stations, regulation, metering and odourisation stations, SCADA and communications and non system assets). Depreciation was applied over the economic lives of the relevant assets in both cases.

NT Gas considered the use of straight line depreciation to be in accordance with the Code, and intends to revisit and where necessary adjust the depreciation schedule to reflect changes in expected asset economic lives.[93]

As shown in Figure 3.1, NT Gas proposed to depreciate the transmission pipeline assets from its DORC valuation of $251.51m at 1 July 1999 to $61.84m in 1 July 2011 using accelerated depreciation. It is further proposed that from 1 July 2011 until the end of the asset's useful life (2066) it will be depreciated on a straight line basis. NT Gas chose 2011 as the timing of the kink to coincide with the expiry of the existing transportation contract. NT Gas believed 'that it is appropriate that the depreciation schedule should mirror the existing contractual and financial arrangements for the pipeline.'[94]

NT Gas proposed the kinked depreciation profile 'to reflect its concern about the sustainability of current levels of throughput over the economic life of the pipeline (that is out to 2066).'[95] NT Gas contended that there is significant uncertainty as to the remaining economic life of the pipeline given the expiration of its foundation gas transportation contract in 2011, the lack of information on future production expectations of the Amadeus Basin, and the potential for the Timor Sea to become the prominent source of gas in the Northern Territory at some future time.[96]

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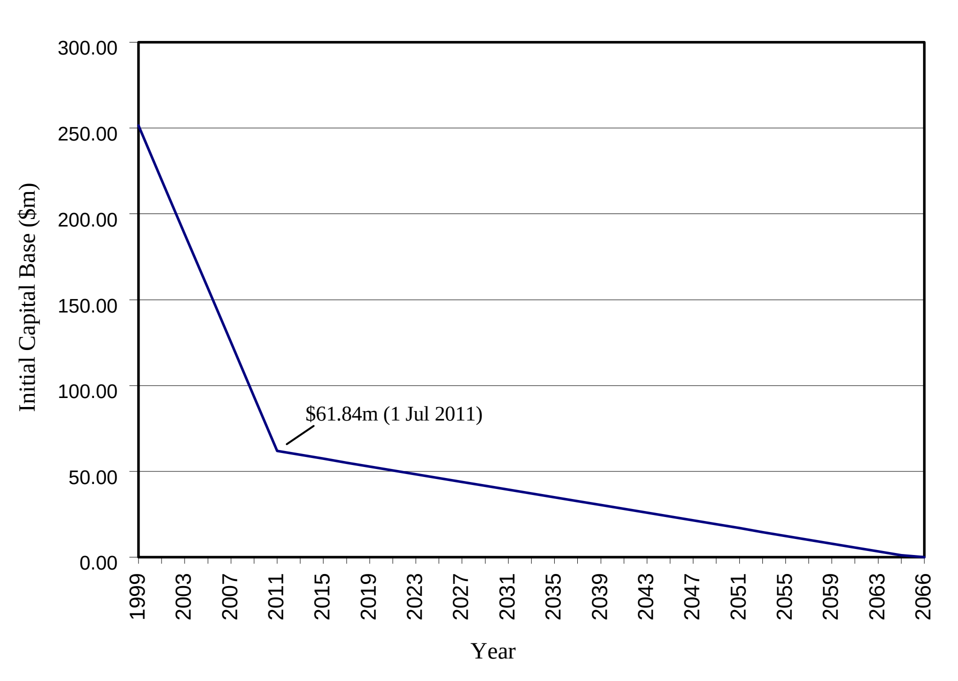
[93] Access Arrangement Information, p. 17.

[94] Access Arrangement Information, p. 19.

[95] Access Arrangement Information, p. 18.

[96] Access Arrangement Information, p. 18.

Figure 3.1: NT Gas' proposed pipeline depreciation schedule (commencing 1 July 1999)



NT Gas submitted that given the growth prospects of the Australian domestic gas market and the depressed demand for LNG in Asia, it is likely that any near term development of the Timor Sea gas fields would focus on delivering gas to the Australian domestic market. Should the Timor Sea project proceed, gas would be brought on-shore to Darwin effectively by-passing the ABDP. Furthermore, should Timor Sea gas be delivered to other parts of Australia, NT Gas believes it unlikely that the gas would be delivered via the ABDP, given the relatively small capacity of the pipeline.[97]

Working capital

In calculating its return on assets, NT Gas has included an allowance in the capital base for working capital, calculated as accounts payable less accounts receivable plus taxation payable. NT Gas estimated the working capital required to fund the day to day operation of the ABDP to be negative $0.28m as at 30 June 1999.[98]

3.3.3 Commission's *Draft Decision*

The Commission proposed the following amendments to NT Gas' access arrangement:

Proposed Amendment A2.4

In order for NT Gas' access arrangement for the ABDP to be approved, the depreciation schedule must be based on straight line accelerated depreciation of the

97 Access Arrangement Information, p. 18.

98 Access Arrangement Information, p. 19.

Commission's initial capital base of $176.2m at 1 July 2001 to a residual value of $61.84m at 1 July 2011.

Proposed Amendment A2.5

In order for NT Gas' access arrangement for the ABDP to be approved, for the purpose of calculating NT Gas' return on capital assets, the working capital component must not be included in the capital base.

3.3.4 Submissions by interested parties

The Commission received substantial comment on NT Gas' proposed depreciation methodology.

In its submission on the Issues Paper, Santos questioned the justification for NT Gas' proposal to accelerate depreciation of the transmission pipeline:

> This depreciation profile equates to $15.6 million per year of depreciation, which adds approximately $1/GJ to the total Reference Tariff. This approach is at odds with the modest $48 million total depreciation applied since the pipeline commenced operation in 1987 (ie $4 million per year).[99]

Santos suggested that should the access arrangement be considered in the context of future use by off-shore gas suppliers (for back haul services), then this would significantly extend the useful life of the ABDP in which case the proposed depreciation schedule would be inappropriate.[100]

NTPG contended that any future risk of stranding is exacerbated by the attempt of NT Gas to extract monopoly rents from users of the reference service. NTPG suggested that the ABDP could remain in operation until 2025 or thereabouts. However, earlier stranding could be brought on by continued attempts of NT Gas and the field operators to extract monopoly rents.[101]

NTPG also stated that the term of the Gasgo[102] agreement ends in 2011, and there was every likelihood that the term of the agreement would be extended until 2025, provided the deliverers of Amadeus Basin gas remain cost competitive and efficient.[103]

Woodside submitted that the proposed accelerated depreciation schedule is inappropriate given that the pipeline is only ten years old. According to Woodside, 'depreciation should be a straight line over the lesser of the commercial lifetime or technical lifetime of each asset type that makes up the pipeline system.'[104]

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[99] Santos submission, 17 September 1999, p. 5.

[100] Santos submission, 17 September 1999, p. 4.

[101] NTPG submission, 2 August 2001, p. 3.

[102] Gasgo is a gas purchasing and transportation arrangement subsidiary of PWC.

[103] NTPG submission, 2 August 2001, p. 3.

[104] Woodside Energy and Shell Development (Australia) submission, 9 September 1999, p. 4.

PWC submitted that, having regard to the risk which has now become apparent that the ABDP will become largely stranded when the PWC contracts terminate in 2011, it is appropriate that the depreciation for the ABDP be accelerated for the period to July 2011.[105]

In response to NTPG's submission, PWC stated that both the Palm Valley and the Mereenie fields are in the production decline phase of their economic lives.

> While the Mereenie field has a better prognosis than the Palm Valley field it is most unlikely, given current and foreseen commercial parameters, that the Amadeus Basin will be able to meet the needs of the market (even the current market) beyond 2015.[106]

PWC also provided the Commission with further evidence on a confidential basis to support its assertion that Amadeus Basin gas reserves are expected to be significantly depleted by 2015.

Further, PWC 'absolutely rejected' NTPG's assertion that there was every likelihood that PWC's agreement with NT Gas would be extended to 2025.[107]

3.3.5 NT Gas' response to the *Draft Decision*

Depreciation

NT Gas did not object to the value of the ICB, when finally determined, forming the basis of the depreciation schedule. NT Gas also agreed with the Commission's proposal that the ICB be depreciated based on the residual value as at 1 July 2011.[108]

Working capital

NT Gas claimed that allowing a return on working capital is consistent with section 8.37 of the Code, which allows for recovery of all non-capital costs except those which would not be incurred by a prudent service provider. NT Gas contend that regardless of whether working capital represents the gap between first expenses and revenues, or the gap between monthly expenses and revenues, the gap must be financed.[109]

3.3.6 Commission's considerations

Depreciation

In the *Draft Regulatory Principles* (DRP),[110] the Commission proposed that service providers identify, at the start of each regulatory review, those assets that are subject to by-pass risk and to nominate a more appropriate asset valuation. The Commission's preferred approach, as outlined in the *Draft Regulatory Principles*, is for the service

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105 PWC submission, 4 October 2001, p. 3.

106 PWC submission, 4 October 2001, p. 8.

107 PWC submission, 4 October 2001, p. 8.

108 NT Gas submission, 14 November 2001, p. 23.

109 NT Gas submission, 14 November 2001, p. 23.

110 ACCC, *Draft Statement of Principles for the regulation of Transmission Revenues*, 27 May 1999, p. 25.

provider to anticipate potential asset redundancy. The Commission would then appropriately provide for the redundancy of the identified assets via an increased depreciation allowance.

In its access arrangement, NT Gas has proposed the use of accelerated depreciation to a residual value of $61.84m in 2011 in recognition of the risk of reduced economic usage or the possibility of stranding faced by the ABDP after that date. However, the economic life of the ABDP for the purposes of the cash-flow analysis is 80 years. Several factors contribute to the risk of stranding on the pipeline and are discussed further below.

Timor Sea gas

In its submission on the Issues Paper, PWC signalled its interest in purchasing Timor Sea gas, depending upon the terms and conditions of supply and when the gas becomes available. However, PWC cautioned that for each of the three potential offshore sources,[111] PWC's demand alone would not be sufficient to economically justify bringing gas onshore to Darwin. At least one other customer of PWC's size would be required.[112]

In November 2000 Woodside and Phillips Petroleum (Phillips) announced that they had reached an in-principle agreement to pursue cooperative development of their Timor Sea gas resources for the supply of gas to Darwin.[113] According to Woodside, it was expected that supply from the Bayu-Undan field will commence in 2004 and production from the Greater Sunrise field is targeted for 2005-7. Woodside stated that the combined reserves of both fields have the ability to meet the long term requirements of a large customer base including Nabalco, PWC and domestic gas markets in South East Australia.[114]

While these plans may have been delayed after Phillips deferred negotiations with East Timor representatives for six months, Phillips has indicated that it will proceed with its $1.5 billion pipeline to bring gas onshore from the Baya-Undan field in the Timor Sea to Darwin.[115] Following Phillips announcement in March 2002 that it had signed a deal to supply two Japanese energy companies with three million tonnes of LNG, Primary Industry Minister Paul Henderson stated that construction of a pipeline linking Timor Sea gas reserves to Darwin was now 90 per cent certain. If the project proceeds, it is expected that the LNG plant would be operating by 2006.[116]

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111 Petrel and Tern field, Bayu-Undan field & Greater Sunrise/Evans Shoal fields.

112 NT and PWC submission, 17 November 1999, p. 6.

113 Woodside Media Release, *Woodside and Phillips agree to Timor sea cooperation*, 30 November 2000.

114 Woodside Petroleum, *Investor Presentation*, December 2000.

115 The Daily Telegraph, *Gas to Burn, and Cheaper Too*, 7 January 2002, p. 42 & NT News, *Darwin Will Get Gas*, 8 February 2002, p. 1.

116 The Australian, *LNG Deal Ensures Go-Ahead*, 13 March 2002, p. 22 & NT News, *Pipeline Now 90PC Certain*, 14 March 2002, p. 8.

Epic Energy has also announced an intention to construct a $1-$1.5 billion high pressure pipeline to transport Timor sea gas from Darwin to Moomba for distribution to South East Australia.[117]

Given the limited capacity of the ABDP, it appears that Epic Energy currently has no intention of utilising the ABDP and should the project go ahead it is more than likely to result in a major by-pass of the pipeline. With the majority of the ABDP's market located in Darwin, it is likely that gas transportation along the ABDP would be limited to supplying a small number of users located along the lower portion of the pipeline. It should be noted however, that while planning for Epic Energy's proposal has advanced significantly, the construction of the pipeline is by no means a forgone conclusion.

Australian Pipeline Trust also announced an alternative proposal for shipping Timor Sea gas to Southern markets, however, at this stage it is unclear to what extent the ABDP might be used.[118]

The Commission cannot rule out the possibility that alternative project proposals involving Timor Sea gas exist. While some of these projects might involve the ABDP, others may by-pass the pipeline entirely. Therefore, the ultimate involvement of the ABDP in the delivery of Timor Sea gas to South East Australia remains uncertain. However, it is evident that the majority of options for the delivery of Timor Gas to Southern markets are likely to result in the partial stranding of the ABDP.

Expiration of foundation contract

The NT Government and PWC have confirmed that the contract between PWC and NT Gas for gas transportation expires in 2011. Whether PWC chooses to renew its contract with NT Gas will depend on the commercial terms being offered for the supply of gas by the Amadeus Basin and offshore gas producers at that time.[119]

Future production expectations of Amadeus Basin

The Commission has not observed or been provided with any evidence to support NTPG's contention that 2025 represents a better estimation of when economically recoverable reserves will be exhausted.[120]

The NT Government and PWC contended that if the Mereenie field were to supply the balance of PWC's requirements for gas, the field's remaining proven reserves would be exhausted by about 2015.[121]

A report to the Timor Sea Consultative Group in May 1999 stated:

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117 Epic Energy Media Release, *MPF Status for Epic's Timor Sea Project*, 8 November 2000.

118 Australian Pipeline Trust Media Release, *Pipeline to Link Northern Australian Gas to Eastern Australia*, 9 May 2001.

119 NT and PWC submission, 17 November 1999, pp. 2 – 3.

120 NTPG submission, 2 August 2001, p. 3.

121 NT and PWC submission, 17 November 1999, p. 3.

> PWC suggests that contracted gas from the Amadeus Basin may not meet demand and anticipates that little gas will be available under existing contracts by 2010 … I understand that the Amadeus Basin producers and PWC are negotiating for additional gas supplies to alleviate shortfalls in gas supply over the period to 2005. However, supplies thereafter remain problematic.[122]

Confidential projections provided to the Commission by the NT Government and PWC and others also lent support to the uncertainty regarding future production expectations of the Amadeus Basin.

Use of ABDP for back haul services

The NT Government and PWC considered that the supply of offshore gas to southern markets through the ABDP is unlikely, given that the size of those markets would require a pipeline of much greater capacity or substantial augmentation of the pipeline. Rather, only a relatively small amount of gas would travel through the pipeline from the Amadeus Basin to supply regional areas such as the McArthur River Mine and Tennant Creek.[123]

While it currently uses imported fuel oil, Nabalco has investigated the viability of using gas as the main energy source for its mine and alumina refinery at Gove (equivalent to 25PJ per annum, with the potential for consumption increasing up to 40PJ). Nabalco envisages that there is little likelihood that gas could be delivered to Gove from the Amadeus Basin, however, it is possible that Timor Sea gas could be economically delivered by upgrading and reversing the direction of pipeline flow and constructing a 600km spur line to Gove.[124]

As discussed in section 3.2.6 of this *Final Decision*, it is unclear if the Timor Sea will proceed and for that reason the Commission has not required a back haul service to be included in the initial access arrangement. However, the Commission has decided to insert a trigger mechanism into this access arrangement, which amongst other things this provides for a review following the introduction of a significant new source of gas into one of the ABDP's markets. If such a review were to occur, the Commission could require the provision of a backhaul service by NT Gas.

Assessment of the risk of stranding

Given the discussion above, the Commission considers that, while the exact timing is uncertain, there is a likelihood that Timor gas will be onshore in the future. Evidence suggests that an alternative source of gas will become necessary in the future, and Timor Sea gas reserves may well be in the best position to meet the demands of current and prospective users. If Timor Sea were to replace the Amadeus Basin as the major supplier of gas to Darwin, a significant portion of the ABDP's current market could potentially be eliminated, severely diminishing pipeline usage.

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122 M J Kimber Consultants, *Opportunities for Timor Sea Gas in the Northern Territory and Queensland*, A Report to Timor Sea Consultative Group Convened by Northern Territory Office of Resource Development, 27 May 1999, p. 12.

123 NT and PWC submission, 17 November 1999, pp. 6 – 7.

124 Nabalco submission, 9 September 1999, pp. 1-2.

It is the Commission's view that the risk of a reduced usage for the ABDP due to the expiration of its foundation contract in 2011 and the uncertainty surrounding the remaining Amadeus Basin gas reserves appears valid. On their own, these circumstances suggest a risk of at least partial stranding. When combined with the potential for Timor Sea gas to replace Amadeus Basin gas as the supply source for the Darwin market, the result is a risk that utilisation of the pipeline would be reduced.

Based on the information provided, the Commission is satisfied that there is sufficient evidence to support NT Gas' assertion that the ABDP is likely to face a risk of stranding after 2011.

Residual value of the pipeline in 2011

As stated earlier, the Commission is satisfied that $61.84m is an appropriate valuation for the ABDP's leased pipeline assets in 2011. In light of further developments, it may become necessary to reassess the residual value, and hence depreciation, of the pipeline in subsequent access arrangements or as a result of the activation of the access arrangement review trigger mechanism.

Non-leased pipeline asset class

The Commission has considered the appropriate depreciation profile for the non-leased pipeline asset class and has determined that it is appropriate to apply straight-line depreciation to each category of this asset class with the exception of the compression system. It is the Commission's view the service provider would seek to recover the capital cost of its non-leased pipeline assets prior to the potential risk of stranding after 2011. Accordingly, the Commission considers that the compression system, unlike other assets of the non-leased pipeline asset category, would not be substantially recovered using straight-line depreciation before 2011. Consequently, the Commission has applied accelerated depreciation to that compression system in manner consistent with that for the leased pipeline assets.

Depreciation of special asset class

As noted in section 2.6.5, a special asset class has been included in the ICB valuation. Unlike the rest of the ABDP's assets, the special asset class has not been depreciated on a straight-line basis, rather the depreciation schedule has been aligned with the planned actual recovery of that cost. This issue is discussed further in Confidential Annexure C.

Conclusion

It should be noted that the redundancy of assets can also reflect an error in judgement on the part of the investor and it may not be appropriate to compensate a service provider for a poor investment decision through accelerated depreciation. While the Commission has accepted NT Gas' proposal for accelerated depreciation in this instance, it will continue to assess other proposals for accelerated depreciation on a case by case basis. Under section 2.24(a) and (e) of the Code, it is the Commission's view that the public interest is served by NT Gas being able to recover its investment in the ABDP. The broader NT community has benefited from the construction of the ABDP due to it facilitating the:

- Development of the NT's indigenous gas reserves;

- Creation of a NT gas market;
- Reduction in the cost of electricity to NT consumers;
- Provision substantial NT-based employment and industry opportunities; and
- Allowing projects, such as the McArthur River, Cosmo Howley and Woodcutters mines to be developed[125].

The Commission is of the view that other provisions of the Code that protect the interests of the service provider are also relevant criteria under section 2.24(g) of the Code that should be taken into account. Accordingly, if the proposed depreciation profile should prove contrary to the interest of the service provider, they may submit revisions to the access arrangement under section 2.28 of the Code at any time during the access arrangement period.

The Commission believes that its approach to accelerated depreciation appropriately reflects the projected usage of the pipeline and the risks of partial stranding after 2011. The Commission considers that the advice provided by PWC supports the likelihood of future events that will effect the economic usage of the ABDP. Future developments in the gas market may, however, affect the risk of stranding faced by NT Gas. The Commission will monitor these developments and reassess the risk of stranding and the value of the pipeline in subsequent revisions. [126]. It should also be noted that the new developments in related markets could also activate the trigger mechanism that has been included in this *Final Decision*. This process will therefore provide a mechanism to protect the interests of users under section 2.24(f) of the Code

The Commission's considerations on this matter also discussed in Confidential Annexure C.

Though Santos suggested that the depreciation profile should take into account the future possible use of the ABDP due to developments in gas production of Australia's northern coast, there remains considerable uncertainty about such investments and the related demand for backhaul services. A depreciation profile based on such assumptions places undue risk on the service provider who may not be able to recover the cost of their investment, such an outcome would be contrary to section 2.24(a). Further the inclusion of a trigger mechanism should a new gas field be developed would enable the Commission to review the depreciation profile. As mentioned previously, this possibility takes into account the interests of users and prospective users under section 2.24(e) of the Code by allowing scope for the adjustment of the depreciation profile and reference tariffs as a result.

NTPG are of the view that the Amadues Basin may continue to produce gas until 2015, however as discussed above the production capacity of the basin remains uncertain. The Commission is not convinced that adjusting the depreciation profile to reflect a

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125 NT and PWC submission to the ACCC in response to the *Draft Decision*, 4 October 2001, p.4

126 Any reduction or increase in the estimated value of the pipeline would be addressed through an adjustment to the depreciation schedule.

2015 risk of stranding is in the interests of the service provider for the reasons discussed in the preceding paragraph. Furthermore, confidential information supplied by PWC indicates that Amadeus Basin reserves are unlikely to last until 2015.

Though Shell is of the view that the depreciation profile is inappropriate given the age of the pipeline, the service provider is considered to face uncertainty regarding the life of the investment beyond 2011. As mentioned previously the inclusion of a trigger mechanism provides an opportunity to adjust the depreciation profile should the pipeline continue to operate after the likely stranding date of 2011. The inclusion of the trigger mechanism is therefore in the interests of users and prospective users under section 2.24(f) of the Code.

The depreciation schedule determined by the Commission and used in the calculation of total revenue is given (in nominal terms) in Table 3.2 below.

Table 3.2: Depreciation schedule (nominal) for 2002-2011

Year ending 30 June	Depreciation ($m)
2002	14.12
2003	15.53
2004	17.09
2005	18.80
2006	20.75
2007	14.44
2008	12.49
2009	13.09
2010	13.71
2011	14.35

Amendment FDA3.3

In order for NT Gas' access arrangement for the ABDP to be approved, NT Gas should adopt the depreciation schedule given in Table 3.2.

Working capital

The Commission notes NT Gas' proposal to include an allowance in the capital base for the purposes of calculating the return on capital.

As part of the assessment of the proposed access arrangement for the Moomba to Adelaide pipeline system the Commission engaged the Allen Consulting Group (ACG) to undertake its own analysis to provide advice in relation to compensation for working capital.

The Commission sought advice as to whether it is appropriate to include an allowance for working capital in the capital base, in conjunction with its application of the post-tax revenue model (PTRM). The PTRM depicts the Commission's cash flow modelling approach, and forecast revenue and expenses on an annual basis as part of the assessment of proposed access arrangements.

ACG provided an excel model that was used to assess the request by NT Gas for the inclusion of an allowance for working capital. Various scenarios indicated that an additional or explicit allowance for working capital in target revenue is unwarranted in this instance. This is due to the favourable allowance provided to NT Gas owing to the timing difference under the target revenue formula adopted by the Commission.

The Commission's determination of required revenue under the cost of service approach centres around cash-flow modelling. In its cash-flow analysis, the Commission assumes that all costs and revenues are incurred on the last day of the financial year. There is, however a difference between the assumed and actual timing of operational cash-flows within each year resulting in a financial benefit to NT Gas.

The cash-flow model used by the Commission assumes that the service provider receives the share of revenue in respect of capital costs on the last day of the year. As revenue is received over the course of each year, it would be expected that target revenue would overstate the opportunity cost associated with investors' funds and would more than offset any shortfall in the cost of financing operating expenditure (ie the required return on working capital).

The Commission's modelling confirms that NT Gas already receives an advantage as a result of the time value of money under the Commission's cash flow modelling that is significantly greater than the working capital cost.

If NT Gas's cash flow were modelled more precisely (such as on a monthly or a daily basis rather than annually) it would be appropriate to explicitly include the working capital component. As a result, however, the total required revenue for NT Gas would be less than that determined under the Commission's modelling approach. Modelling cash flows on an annual basis results in reduced administration and compliance costs while adding to the transparency of regulation.

Conclusion

As the PTRM already includes an implicit allowance for working capital, the Commission's cash flow modelling errs on the side of the service provider by providing for total revenue that exceeds that would be calculated in a more precise and explicit model. Explicit compensation for working capital in the NT Gas cashflows would result in working capital being double counted. This is true regardless of whether the working capital cost arises from an initial outflow at the time of pipeline acquisition or from ongoing operational timing differences between expenditure and revenue.

Based upon the advice from the ACG and the application of its model to NT Gas circumstances, the exclusion of the working capital allowance will not be contrary to the legitimate interests of the service provider under section 2.24(a) of the Code as the Commission's approach to modelling already sufficiently compensates NT Gas for any costs associated with working capital.

The potential to double count working capital, if it were to be included as a specific item in the cashflow modelling would produce a windfall gain to the service provider. This would be contrary to the interests of users under section 2.24(f) of the Code who would be offered reference tariffs at a level higher than they other wise should be.

In the absence of submissions on NT Gas' proposal, the Commission considers it a relevant consideration under section 2.24(g) for it to be guided by the advice of consultants when assessing the service provider's request.

For these reasons, the Commission will not provide for the inclusion of working capital in the value of the capital base.

Amendment FDA 3.4

In order for NT Gas' access arrangement for the ABDP to be approved, for the purpose of calculating NT Gas' return on capital assets, the working capital component must not be included in the capital base.

3.4 Rate of return

3.4.1 Code requirements

As noted earlier, the Code (sections 8.30 and 8.31) states that the rate of return should provide a return that is commensurate with prevailing conditions in the market for funds and with the commercial risk associated with providing the reference service. The Code suggests as an example using a weighted average of the returns applicable to each type of capital (equity, debt and any other source of funds), commonly known as the 'weighted average return on (cost of) capital' or 'WACC'. Such returns would be determined on the basis of a well accepted financial model such as the capital asset pricing model (CAPM). The financing structure assumed should also reflect standard industry structures and best practice. However, a service provider may adopt other approaches if the regulator is satisfied that the objectives regarding the design of the reference tariff and reference tariff policy set out in section 8.1 of the Code are met.

3.4.2 NT Gas' proposal

NT Gas relied heavily on the Commission's *Final Decision* for the access arrangements proposed by Transmission Pipelines Australia Pty Ltd and others (Victoria *Final*

Decision)[127] in calculating the weighted average cost of capital (WACC), but argued for a higher WACC on the basis that the ABDP is a comparatively riskier venture.

NT Gas pointed out the following differences between the ABDP and the Victorian infrastructure:[128]

- The Victorian decision was substantially completed prior to the full impact of the accident at the Longford gas processing plant was known, and therefore, the risks associated with pipeline investment are unlikely to have been fully incorporated into the Commission's decision on risk;
- There is a greater risk of field failure as the Amadeus Basin is much smaller than Bass Strait and there is less associated oil, on site and off site support and analysis available to the Amadeus Basin field;
- The location and commercial environment is more risky than in Victoria. Much of the ABDP is located in remote and relatively inaccessible regions. Demand for gas is dependent on the condition of the resource market, the armed forces and South East Asian economies. In addition, NT Gas does not hold easements for the pipeline but relies on the NT government providing right of way;
- The inability of insurance to adequately cover all natural and force majeure style risks. ABDP is subject to greater risks than other Australian pipelines ie flooding, wash outs and earthquakes. These disasters affect gas usage levels of ABDP customers which cannot be fully recovered from 'natural risk' style expenses through insurance;
- Explicit regulation has never been applied to the ABDP. It is uncertain how industry participants and customers will react to regulation;
- The much lower levels of maturity of the ABDP's markets. Markets are slowly developing but there is only a limited range of applications suitable for gas;
- The much higher levels of concentration of usage among ABDP's consumers. PWC has contracted 99 per cent of pipeline throughput to generate electricity and as a consequence ABDP is vulnerable to any shift in fuel usage or gas source;
- The risky nature of many of the ABDP's smaller consumers. Mining sites are usually served by dedicated lateral pipelines which are uneconomic if the mine folds. Given the exposure to commodity markets this risk of failure is significant; and
- The high city gate price for gas in the NT restricts market growth and the competitiveness of natural gas with other fuels.

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127 ACCC, Access arrangements proposed by Transmission Pipelines Australia Pty Ltd and others, *Final Decision*, 6 October 1998.

128 Access Arrangement Information, pp. 22-25.

In view of these risks specific to the ABDP, NT Gas proposed a pre-tax real WACC of 11 per cent.

The underlying parameters, equations and other assumptions used within the CAPM framework to develop the proposed post-tax nominal WACC and other WACC derivatives are summarised below in Table 3.3.

Table 3.3: Parameter ranges proposed by NT Gas for WACC calculations

Parameter		**Ranges**	
		High	Low
General Economic Parameters	Inflation Corporate Tax Rate Imputation Take Up Rate	2% 36% 25%	3% 36% 50%
Gearing	Debt Equity	50 50	60 40
Cost of Debt	10 Year Bond Rate 2010 CPI Linked Bond Rate Debt Margin Bank Costs	5.9% 3.7% 1.4% 0.5%	5.5% 3.4% 1.0% 0.5%
Nominal Cost of Debt	Based on 10 Year bond rate Based on CPI Linked Bonds	7.3% 7.6%	6.5% 6.9%
Cost of Equity	Market Risk Premium Asset Beta Equity Beta Margin for Asymmetric Risk Margin for Self Insured Risk	7.0% 0.9 1.65 1.0% 0.5%	6.0% 0.55 1.25 0 0
Nominal Cost of Equity	Based on 10 Year Bond Rate Based on CPI Linked Bonds	19.0% 19.3%	12.9% 13.3%
WACC Results	Nominal Post Tax WACC Nominal Pre Tax WACC Real Pre Tax WACC	10.9% 17.0% 14.1%	6.5% 10.2% 7.5%

NT Gas modified the usual CAPM calculation of the cost of equity by adding a measure for asymmetric risk and an allowance for self insurance. Consequently, NT Gas' nominal cost of equity (r_e) equation is:

$$r_e = r_f + \beta_e (r_m - r_f) + \text{asymmetric risk} + \text{self insurance}$$

The nominal cost of equity is a key variable in determining the rate of return. NT Gas defined the post-tax nominal WACC (W) by the formula:

$$W = r_e \frac{(1-T)}{(1-T(1-\gamma))} \frac{E}{D+E} + (r_f + D_m)(1-T)\frac{D}{D+E}$$

NT Gas' conversion from post-tax nominal to pre-tax real WACC was performed on the basis of firstly adjusting for tax and then for inflation.

Recognising that the upper and lower ends of all the ranges of the above parameters are unlikely to occur simultaneously, NT Gas identified the following as being reasonable ranges:

Parameter	Low	High
Cost of Equity	14.3%	17.3%
Cost of Debt	6.7%	7.4%
Real Pre Tax WACC	8.5%	11.7%

NT Gas chose a pre-tax real WACC of 11 per cent from the upper end of the range, arguing that a WACC from the lower end could be a disincentive for investment given the immature state of infrastructure development in the NT.[129]

3.4.3 Commission's *Draft Decision*

Based on its own analysis and the parameters identified by the Commission as being appropriate to NT Gas within the access arrangement period, a post-tax nominal cost of equity of 11.96 per cent was derived. The pre-tax real WACC consistent with this was 6.49 per cent.

3.4.4 Submissions by interested parties

Woodside submitted that the pre-tax real WACC of 11 per cent proposed by NT Gas was too high and that this was the driver for the proposed 'unrealistic' tariffs. Woodside stated:

> …there would seem to be no strong qualitative reasons that suggest that the systematic risk of the Northern Territory assets would be any different to those in other parts of Australia or, for that matter, the world. That is, there is no basis for Northern Territory onshore gas transmission pipeline assets' WACC to be greater than the rates determined in Victoria.[130]

NTPG disputed the acceptance of a 60:40 gearing ratio suggested by NT Gas, and contended that for the unique circumstances of the ABDP, a prudent operator would finance the pipeline using debt financing to the greatest possible extent. NTPG stated:

> This is quite a different situation than for most other Australian gas pipelines lacking a foundation contract guaranteed by the Crown, which assures a revenue stream from commissioning to 2011, with likely extension to 2025 provided gas is delivered on a cost competitive and efficient manner. This revenue stream acts as collateral to support an assumption of continued debt financing. As the cost of debt is less than the cost of equity a prudent operator would employ this collateral to obtain a greater proportion of debt financing than 60%.[131]

In its submission on the Issues Paper, NTPG also commented that, given the ABDP's revenues are underpinned by the NT Government's guaranteed shipping contract, the long term Australian government bond rate would be the appropriate cost of debt.[132]

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[129] Access Arrangement Information, p. 29.

[130] Woodside Energy and Shell Development (Australia) submission, 9 September 1999, p 2.

[131] NTPG submission, 2 August 2001, p. 3.

[132] NTPG submission, 12 September 1999, p 5.

Both Santos and Nabalco submitted that the proposed real pre tax WACC is too high given the WACC determinations made in respect of other declared pipelines, and the current gas delivery arrangement.[133] Nabalco stated:

> In particular the risk factor appears overstated for what is essentially a fixed supply to a Government utility.[134]

3.4.5 NT Gas' response to the *Draft Decision*

NT Gas claimed that the Commission's proposed rate of return was not consistent with section 8.30 of the Code, and setting the cost of capital at such a low level has the potential to detrimentally affect the interests of users in the longer term. Further, NT Gas claims that low returns on regulated investment will jeopardise plans for future pipeline construction and interconnection.[135]

In its submission NT Gas stated:

> The WACC approach adopted by the Commission provides a framework for identifying the cost of capital and produces a range of values rather than a precise answer. If returns are set below the market cost of capital, the investment necessary for development and innovation will be discouraged. Accordingly, once the possible range for the cost of capital is identified, the Commission should establish a return at the higher, rather than lower, end of that range to ensure that its decision does not deter necessary investment.[136]

WACC parameters

Debt margin

NT Gas believed that the debt margin of 1.2 per cent used in the *Draft Decision* was incorrect, as it was not based on capital market information. NT Gas stated that while a debt margin of 1.2 per cent was used in the CWP *Final Decision*, this margin was determined on the basis of a particular transaction rather than on the basis of capital market information.[137]

NT Gas suggested that a debt margin of 1.5 per cent should be used. A similar debt margin determined by the ORG based on 'current information from capital markets' in its decision on the electricity distribution price review was provided as supporting evidence.[138]

Market risk premium

NT Gas believed that while the *Draft Decision* assumed a market risk premium of six per cent, it was indicated that the Commission could consider a lower value to be appropriate. NT stated that studies indicate that the long-term arithmetic mean of the

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[133] Nabalco submission, 9 September 1999, p 2 & Santos submission, 17 September 1999, p. 5.

[134] Nabalco submission, 9 September 1999, p 2.

[135] NT Gas submission, 14 November 2001, p. 17.

[136] NT Gas submission, 14 November 2001, p. 17.

[137] NT Gas submission, 14 November 2001, p. 18.

[138] NT Gas submission, 14 November 2001, p. 18.

historically observed market risk premium exceeds six per cent. Accordingly, NT Gas believed that a market risk premium of less than six per cent could not be justified.[139]

Post tax approach

NT Gas submitted that the modelling of tax costs in cash flows rather than directly into the WACC was not desirable because:

- it suggests that decisions as to corporate structuring and tax planning are matters for decision by the regulator, rather than company management;
- the allowed rate of return relies on assumptions made by the Commission as to the consequences of the application of complex and often contentious tax legislation;
- the additional complexities increase the potential for error; and
- it adversely affects the intended operation of government tax incentives.

Imputation Credits

NT Gas noted that the *Draft Decision* largely accepted NT Gas' value for gamma. However, NT Gas considered that no move should be made to increase the value of gamma without extensive further study and consultation.

Asset beta

NT Gas believed that the Commission's proposed asset beta of 0.50 was incorrect and that an asset beta of 0.55 to 0.90 is appropriate for the following reasons:

- the market served by the ABDP is smaller and not as deep as that served by the Victorian gas transmission assets and the MAPS; and
- the ABDP faces a clear risk of stranding after 2011 or bypass before that date if Timor Sea developments proceed.

3.4.6 Commission's considerations

Calculation of WACC

Given the critical nature and complexity of the WACC in determining revenue, hence profits, there is a substantial degree of sensitivity regarding the value of the WACC. Consistent with section 8.30 of the Code, the Commission's approach is to determine the WACC with due consideration of prevailing financial market benchmarks[140] and the level of commercial risk involved in maintaining the service infrastructure through which the reference service is delivered.

NT Gas converted the post-tax nominal WACC to a pre-tax real WACC by adjusting for tax and then for inflation. As noted in its Victoria *Final Decision*, the Commission

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139 NT Gas submission, 14 November 2001, p. 18.

140 The Commission has used financial market data as at 3 December 2002 to determine the WACC in this *Final Decision*

considers that such conversions to the pre-tax real WACC give rise to errors.[141] In that instance, the Commission used cash-flow modelling to derive the pre-tax real WACC that yielded the post-tax nominal cost of equity indicated by the CAPM.

The Commission indicated in its Victoria *Final Decision* that a post-tax WACC framework is preferred to a pre-tax WACC framework. Commercial returns to investors, including those indicated by CAPM, are invariably expressed in post-tax nominal terms. If two investments involving similar risks provide the owner with the same return before tax but a different net return after tax, an investor will prefer the investment that gives the higher net after-tax return. Indeed, if the investments are available as shares listed on the stock exchange the price of the one with the higher return will be bid up relative to the other so that the post-tax returns to investors are equalised.

It follows that if, in regulating a service provider's revenues, the regulator takes account of the taxes likely to be paid by the service provider given its financial structure, the output from application of CAPM to the regulatory accounts will be the appropriate commercial return for the business.

If there are features of the taxation system that give benefits to shareholders in addition to dividend cash-flow, for completeness these need to be taken into account when assessing the prospective return to shareholders. The value of imputation credits to shareholders is one such benefit to be accounted for in the Australian context.

Following the release of the *Draft Regulatory Principles*,[142] the Commission has applied the post-tax methodology in all of its subsequent decisions including the Transgrid *Final Decision*,[143] Central West Pipeline (CWP) *Final Decision*,[144] MAPS *Final Decision*,[145] MSP *Draft Decision*[146] and the GasNet *Final Decision*[147].

Section 8.30 of the Code states that the rate of return used in determining the reference tariff should provide a return that is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the reference service. In the Commission's view, a post-tax WACC better achieves that objective than does a pre-tax WACC. Applying a pre-tax WACC without consideration of the service provider's

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141 ACCC, Access arrangements proposed by Transmission Pipelines Australia Pty Ltd and others, *Final Decision*, 6 October 1998, p. 61.

142 ACCC, *Draft Statement of Principles for the Regulation of Transmission Revenues*, 27 May 1999.

143 ACCC, 'NSW and ACT Transmission Network Revenue Caps 1999/00 – 2003/04', *Final Decision*, 25 January 2000.

144 ACCC, 'Access Arrangement by AGL Pipelines (NSW) Pty Ltd for the Central West Pipeline', *Final Decision*, 30 June 2000.

145 ACCC, 'Access Arrangement proposed by Epic Energy South Australia Pty Ltd for the Moomba to Adelaide Pipeline System', *Draft Decision*, 16 August 2000.

146 ACCC, 'Access Arrangement by East Australian Pipeline Limited for the Moomba to Sydney Pipeline System' *Draft Decision*, 19 December 2000.

147 ACCC, 'Access Arrangement by GasNet Australia for the Principal Transmission System' *Final Decision*, 13 November 2002.

financial needs in the light of its tax liabilities would risk under or over-providing for revenues over the life of the asset. Therefore, the Commission is of the view that the post-tax methodology is superior and has applied that methodology in determining NT Gas' revenues and tariffs in this *Final Decision*.

In respect of NT Gas' comments that modelling tax costs in cash flows is not desirable, several qualifications are warranted. First, it must be recognised that the Commission applies standard tax legislation. As noted by NT Gas, tax legislation is often complex, however these complexities can often result in further tax concessions. For example, if NT Gas is able to arrange its affairs in such a way as to obtain additional concessions such that actual tax liabilities are less than the tax allowances calculated by the Commission, NT Gas will benefit from the difference.

The Commission therefore considers that it is misleading to claim that the Commission's approach to cash flow modelling in any way constrains the affairs of the business. Any potential error in the estimation of the tax liabilities would favour NT Gas and be retained by the business as additional profit.

It should also be noted that the Commission's approach does not have the effect of reducing regulated revenues below that which provides an expected return commensurate with the risks perceived by equity investors.

WACC parameters

The development of a WACC figure from the cost of equity requires certain parameters and assumptions. The values assigned to the financial parameters remain contentious and warrant discussion in some detail since they form the basis for determining the permitted rate of return on the regulated assets. Accordingly, each parameter will be dealt with in turn in the remainder of this section.

The key parameters are:

1. the risk-free interest rate (r_f), the real risk-free rate (rr_f) and, by implication, the anticipated rate of inflation (f) and the interest rate applicable to debt (r_d);
2. the market risk premium (MRP);
3. the likely level of debt funding (D/V);
4. the likely utilisation of imputation credits (γ);
5. the effective tax rate (T_e); and
6. the equity beta (β_e) relevant to stand-alone operation within the proposed regulatory framework.

Interest rates and inflation

As discussed earlier, the Code (section 8.30) states that the rate of return should be 'commensurate with prevailing conditions in the market for funds.' This implies that all information for deriving the rate of return should be as up to date as possible at the point the access arrangement comes into effect. It also means that the rate of return should match the circumstances (economic conditions) of the regulatory framework. For example, the term of the interest rate should correspond to the term of the regulatory period. Interest rates and inflation expectations are parameters set by the financial markets on a daily basis and are readily determined.

Generally, the relevant WACC for regulatory purposes should be a forward-looking concept, giving an indication of the minimum average expected commercial return on debt and equity. Selected interest rates and inflation estimates relevant to the setting of the WACC have been derived from financial market data and are shown below in Table 3.4.

NT Gas adopted a nominal ten-year bond rate and a CPI indexed bond 2010 series plus inflation component as indicators of the risk free rate. NT Gas recognised that these rates should be 'on the day' but has averaged the figures over an undefined 'short period of time' to remove volatility.[148]

In its *Draft Decision*, the Commission considered that the term associated with the risk free rate should coincide with the five year duration of the access arrangement period for the ABDP. Accordingly, five year rates were used in the CAPM.

However, since the *Draft Decision*, NT Gas sought, and this *Final Decision* approves, a ten-year access arrangement period. The Commission considers that it is appropriate to maintain the use of interest rates that correspond with the length of the access arrangement period. Thus, for the ABDP, which is seeking a ten-year access arrangement period, the yield on bonds with a term to maturity of ten years is used. This approach follows on from the CWP *Final Decision* which also aligned the length of the access arrangement period with the risk free rate, both for ten years.

Although, in theory, an on-the-day rate is considered the best indicator of the opportunity cost of capital at any point in time, the Commission accepts that there is some merit in averaging rates over a short period to abstract from day-to-day market volatility. The *Draft Regulatory Principles* proposes the use of a 40-day moving average of the relevant bond rates covering the period prior to the decision analysis. This methodology was used by the Commission in the Central West Pipeline, the MAPS, Transgrid, GasNet *Final Decisions* and the MSP *Draft Decision*.

This approach has been adopted by the Commission for NT Gas, resulting in a nominal risk-free rate of 5.52 per cent and a real risk-free rate of 3.26 per cent as indicated in Table 3.4 below. Further, the Commission has maintained the use of a 40-day moving average of rates to smooth out any short-term volatility that may occur in bond markets.

[148] Access Arrangement Information, p. 27.

Table 3.4: Current financial market interest rates and inflation expectations

Financial Indicator	Proposed by NT Gas (per cent p.a.)	40-day moving average (per cent p.a.)[(a)]
10 year government bond rate	5.5 - 5.9 [(b)]	5.52
CPI indexed bonds (2010 series)	3.4 - 3.7 [(b)]	3.25
CPI indexed bonds (2015 series)	-	3.36
Estimated 10 year real rate[(c)]	-	3.26
Implied 10 year inflation expectation[(d)]	-	2.19

Notes: (a) Based on daily closing quotations as published by the Reserve Bank of Australia. The Commission finalised its calculations of WACC for this *Final Decision* on 3 December 2002.

(a) NT Gas calculated this as the average over an undefined 'short period of time'.

(b) Interpolations based on indexed bond figures (2010 & 2015).

(c) Inferred from the difference between nominal and real interest rates over the corresponding period using the Fisher Equation, (1+ir) = (1+in)/(1+CPI), where:
ir = real interest rate, in = nominal interest rate and CPI = inflation rate.

While the inflation rate is not an explicit parameter in the WACC estimation, it is an inherent aspect of the nominal risk-free rate and cost of debt parameters. It is fundamental to deriving real rates of return, which are used in the target revenue and economic depreciation calculations. It is also an important determinant of the effective tax liability. NT Gas has suggested a range for the annual rate of inflation of two to three per cent over the initial ten year price setting period but has used a rate of 2.5 per cent in all its analysis.

An indication of the rate of inflation anticipated by financial markets is provided by the difference between the nominal bond rates and rates for inflation-indexed bonds for the same term. The indexed bond series have maturity dates that do not correspond to current five or ten-year bond rates. However, the corresponding figures are readily derived by interpolation and are shown in Table 3.4 above. These figures represent the real risk-free rate corresponding to the current nominal risk-free rate (based on the ten-year bond yield) and indicate that the current expectation of inflation (f) over the initial regulatory period is 2.19 per cent.

Accordingly, the Commission considers that NT Gas' revenue requirement for the access arrangement period should be recalculated using a forecast rate of inflation of 2.19 per cent and observed inflation rates where this is appropriate.

As discussed in section 3.9.6, the absence of a CPI adjustment mechanism in NT Gas' tariff escalator means that NT Gas bears the risk that the inflation rate may be lower or higher than currently forecast, resulting in tariffs which may over or under compensate for actual costs. An amendment to the access arrangement is proposed by the Commission to implement a CPI-X mechanism to calculate future tariffs. This amendment removes the inflation risk currently borne by NT Gas in its proposed access arrangement.

Debt margin

In its proposed access arrangement, NT Gas suggested that 100 to 140 basis points represents an appropriate debt margin for a company with NT Gas' characteristics, and that the cost of debt should be determined on the basis of this margin.

A debt margin of 120 basis points was adopted by the Commission in its *Draft Decision* for the ABDP. The 120 point margin was added to the yield on a five year nominal risk free rate of 5.0 per cent to obtain a nominal cost of debt figure of 6.2 per cent for use in the WACC estimation. The proposed access arrangement was for a five-year period. Subsequent to the *Draft Decision*, NT Gas has argued that the appropriate margin for the cost of debt is 150 basis points above the relevant risk-free rate.[149]

As noted in the *Draft Statement of Principles for the Regulation of Transmission Revenues* (DRP),[150] the Commission considers it appropriate to abstract from the actual cost of debt facing the service provider as the actual cost of debt may not reflect efficient finance sourcing. Thus, the Commission is of the view that the cost of debt should be determined through reference to a benchmark debt margin that is consistent with the other benchmarks adopted.

The calculation of the benchmark debt margin is essentially an empirical matter. Specifically, the calculation of the debt margin requires the Commission to consider two distinct empirical questions: the appropriate benchmark credit rating of the service provider; and the market observed debt margin associated with that benchmark rating.

With regard to the credit rating of a service provider, the Commission considers it appropriate to estimate a benchmark rather than use an actual credit rating given that the creditworthiness of the entity is in part under managerial control and the use of a benchmark is consistent with other assumptions. The Commission is of the view that relevant Australian gas transmission and distribution companies should be used as the basis of a benchmark. It is important for consistency that these companies are stand-alone entities and are void of government ownership. Further, it is important that the gearing ratio of the entities used to calculate the debt margin are not significantly different from the gearing assumptions used to determine the WACC.

Table 5.1 below sets out the long-term credit rating for four Australian transmission and distribution gas companies that meet the stand-alone entity criteria and have been assigned a credit rating from ratings agency Standard and Poors.[151]

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[149] NT Gas submission, 14 November 2001, p. 18.

[150] ACCC, *Draft statement of principles for the regulation of transmission revenues*, May 1999, p. 82.

[151] A stand-alone entity may be defined as an entity that does not have a parent company (a company that holds the majority of voting stock). With regard to the companies used to estimate the benchmark credit rating, approximately 18 per cent of Envestra Ltd is owned by Cheng Kong Infrastructure Holdings (Malaysia) Ltd and another 18 per cent is owned by Origin Energy Ltd (source: http://www.envestra.com.au). Further, 45 per cent of AlintaGas is owned by WA Gas Holdings Pty Ltd, which is jointly owned by Aquila Inc and United Energy Limited (source: http://www.alintagas.com.au).

Table 5.1: Credit rating associated with stand-alone energy companies

Company	Long-term rating
GasNet Australia(1)	BBB
Envestra Ltd(1)	BBB
AlintaGas(1)	BBB
AGL(2)	A

Source (1): www.standardandpoors.com.au (September 2002)
Standard and Poor' s 2002 (May), *Australian and New Zealand CreditStats,* p.33- 34
Source (2): Standard and Poor' s 2002 (29 September), News Release: Ratings on AGL affirmed after Pulse acquisition; outlook stable

On the basis of this data, the average credit rating of these entities approximates BBB+.[152] This data is also corroborated by analysis undertaken by financial market experts. Accordingly, the Commission considers that a BBB+ credit rating represents an appropriate proxy credit rating for the benchmark company.[153]

Having established a proxy credit rating, a benchmark debt margin can be determined. Debt is raised by asset owners either through bank markets or through the private and public capital markets. Debt requirements have largely been met by the bank market for projects involving construction in Australia.[154] Evidence suggests that for energy infrastructure, re-financing arrangements have also largely been met by institutional lenders, although capital markets have played a role (for example, the November 2000 and March 2002 debt issues by GasNet).[155]

In determining the cost of debt for benchmark firm the Commission used data supplied by ABN Amro on specific bond issues and *CBA Spectrum* data on corporate bond spreads developed by Commonwealth research as the basis of the debt margin calculation. After further consideration, the Commission has decided to calculate the debt margin based solely on the data provided by *CBA Spectrum*. The data provided by this service is based on an econometric credit spread model that was developed by Commonwealth research in consultation with academics and industry advisers. The CBA data is preferable to raw corporate bond data as it addresses several issues such as limited observations and non-linear yield curves. It is also favourable as it is transparent and provides specific data for bonds with differing maturities. The Commission notes that research by the Essential Services Commission concluded that yields produced by the Commonwealth Bank model are close to the indicative pricing for corporate bond yields provided by other research houses.[156]

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152 Recent evidence suggests that with the exception of Envestra, the gearing ratio of the companies used to calculate the benchmark are within a 10 per cent range of the 60:40 benchmark rate (Envestra has a gearing ratio of approximately 80 per cent (www.envestra.com.au)).

153 Some of these companies have non-regulated activities, which all else being equal, should lower the overall credit rating. Therefore, the rating for a 100 per cent regulated benchmark company would generally be higher than the benchmark determined above.

154 Macquarie Bank, *Issues for debt and equity providers in assessing greenfields gas pipelines,* Report for the ACCC, May 2002. p. 7.

155 ibid., p. 22.

156 Essential Services Commission, 2002, Gas Access Arrangements Final Decision, p. 141.

In light of this evidence, the Commission considers that the proposal put forward by NT Gas for a debt margin of 100 – 140 basis points, based upon a five-year access arrangement period may underestimate the current market debt margin associated with a benchmark regulated transmission or distribution entity. NT Gas did not submit a revised estimate for a cost of debt based-upon a ten-year access arrangement period. The Commission is of the view that the use of a ten year cost of debt calculation is consistent with the legitimate interests of the service provider under section 2.24 of the Code.

The Commission has determined the cost of debt by taking the 40-day average for the cost of debt as derived by the margin between the Commonwealth Bank of Australia market rate for a BBB+ firm minus the Commission's risk free rate for ten year bonds. Such a measurement approach should limit any market abberations that may come through in the data given thin corporate bond markets. This approach echoes the methodology adopted by the Essential Services Commission in its recent *Final Decision* on gas distributors.[157]

NT Gas submitted that the debt margin should be set on the basis of capital market information. The Commission has sought to ensure that the cost of debt is reflective of the market margin for a ten year-bond by determining a 40 day average of the debt margin. It is the Commission's view that this approach provides for the derivation of WACC parameters that are commensurate with the prevailing conditions in the market. It is the Commission's view that this objective is a relevant consideration under section 2.24(g) of the Code.

Using the methodology outlined above, the average debt margin over the 40-day period used to measure the risk free rate for BBB+ bonds with ten-year maturities was 154 basis points.

The Commission is of the view that the benchmarking approach to determining the credit rating of NT Gas and the consequential cost of debt will provide the correct incentive structure for service provider to deliver it reference service at the least efficient cost and provide an efficient for NT Gas to outperform the Commission determined cost of debt. These outcomes will benefit the service provider and users in accordance with section 2.24(a) and (b) of the Code.

The 154 basis point margin in combination with the nominal risk-free rate of 5.52 per cent suggests a nominal cost of debt (r_d) figure of 7.07 per cent for use in the WACC estimate. With an inflation rate of 2.19 per cent the corresponding real cost of debt (rr_d) is 4.78 per cent.

The Commission considers that the above approach for establishing the debt margin is cogent, transparent and consistent with the determination of the other WACC parameters. Through reference to current market evidence, it is considered that this approach promotes the service providers legitimate business interests and investment under s. 2.24(a) of the Code and promotes the economically efficient operation of the ABDP under section 2.24(d). The use of relevant market to market data and thus the

[157] Essential Services Commission, 2002, Gas Access Arrangements Final Decision, p. 141.

replication competitive markets, the Commission considers that the approach promotes the public interest, including the public interest in having competitive markets under section. 2.24(e).

The Commission notes the comments by NTPG that the cost of debt should be the long-term government bond rate, however, due to the operation of the lease arrangement for the ABDP and its related financing, the Commission is of the view that a market-determined cost of debt more accurately reflects the commercial environment of NT Gas. The Commission is of the view that the use of a margin other than the proposed bench-mark cost of debt would be contrary to the legitimate interest of the service provider under section 2.24(a) of the Code.

The market risk premium

The market risk premium is a parameter in the CAPM that, together with the risk-free rate and firm-specific equity beta, determines the expected cost of equity in the business.

NT Gas proposed a range of 6.0-7.0 per cent for the market risk premium. This has been the conventionally accepted range under the classical tax system. However, as reported in the Commission's Victoria *Final Decision*, Professor Kevin Davis has suggested that this may not be in keeping with the forward-looking CAPM framework favoured by the Commission.[158] For example, the more stable inflationary environment now prevailing may mean that the relevant market risk premium is less than has been observed in the past.

Following the introduction of tax imputation credits, the premium as measured in the conventional way, would have fallen to reflect the additional value of franking credits. In the Victoria *Final Decision* the Commission considered the probable range to be 4.5-7.5 per cent and chose to use a mid-value of 6.0 per cent.[159] More recently, in the *Draft Regulatory Principles*, the Commission suggested that a market risk premium of around 5.0 per cent may be more appropriate given the downward reassessment of the market risk premium over recent years.[160]

The Commission requested Dr Martin Lally assess various approaches to, and estimates of, the market risk premium. Doctor Lally determined that the average estimate for Australia was 6.1 per cent and noted that although many empirical estimates of the market risk premium were available, they diverged significantly and there was no clear

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158 Professor Kevin Davis, *The Weighted Average Cost of Capital for the Gas Industry*, report prepared for the Commission and the Office of the Regulator General, 18 March 1998, p. 14.

159 ACCC, Access arrangements proposed by Transmission Pipelines Australia Pty Ltd and others, *Final Decision*, 6 October 1998, p. 53.

160 ACCC, *Draft Statement of Principles for the Regulation of Transmission Revenues*, 27 May 1999, p. 79

consensus value. He concluded that ‘all of this suggests that the ACCC’s currently employed estimate of 6 percent is reasonable, and no change is recommended’.[161]

The ESC *Draft Decision* included a detailed discussion on the market risk premium. Having regard to all the information before it and adopted an estimate of the market risk premium of 6.0 per cent.[162] While the gas distributors expressed concern at this outcome, and the ESC’s analysis, the ESC adopted the same value in its *Final Decision*, concluding:

> The Commission [ESC] remains of the view that the weight of evidence discussed above provides a sound basis for adopting an estimate of the equity premium that is below the point estimate provided by the average of the historical premia, but which otherwise is within the range provided by historical returns, given the variability associated with this measure. Indeed, the evidence discussed above (including the new information received since the Draft Decision) would suggest that many market practitioners would adopt an assumption about the equity premium that is lower than the assumption of 6 per cent that the Commission has adopted in previous decisions and in the Draft Decision.[163]

As part of this *Final Decision*, the Commission has reviewed a number of works on the issue of determining an estimate of the market risk premium. The Commission concurs with Lally and the ESC that there is no clear consensus on the appropriate method or value for the market risk premium. Nevertheless, a point estimate is required for the CAPM and calculation of a rate of return. As a result, the Commission, like the ESC, has attempted to use an estimate that has reference to both historical data and forward looking information.

In determining an appropriate estimate of the market risk premium for this *Final Decision* the Commission has carefully considered the additional information raised in recent submissions. In addition, the Commission has considered NT Gas’ legitimate business interests pursuant to section 2.24(a) of the Code. The Commission acknowledges the studies that suggest that the appropriate estimate of market risk premium is less than the 6.0 per cent the Commission has generally used to date in its regulatory decisions.

The Commission accepts that there is considerable information from recent studies of financial markets suggesting that the market risk premium is now lower than it has been in past decades. On the other hand, the Commission acknowledges that indications of a downward trend are also not fully accepted by market participants and commentators. However, there does appear to be sufficient support to suggest that the market risk premium is now unlikely to be above 6.0 per cent.

On balance, in light of the information available at this time, and the requirements of the Code, the Commission does not consider that it would be appropriate to move from the value of the market risk premium adopted in its *Draft Decision*. Accordingly, for the calculation of the benchmark rate of return for the ABDP the Commission has

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161 M Lally, *The cost of capital under dividend imputation*, June 2002, p. 34. A 6 per cent MRP has also been endorsed by Professor Officer: ‘Trends in market risk premium’ presentation to the open forum ‘Key WACC issues in the regulation of electricity and gas transmission’, 24 June 2002.

162 ESC, *Draft Decision: review of gas access arrangements*, July 2002, p. 225.

163 ESC, *Final Decision: review of gas access arrangements*, October 2002, p. 336.

adopted a market risk premium estimate of 6.0 per cent. The Commission has used 6.0 per cent in its WACC calculations for the ABDP. This figure is at the bottom end of the range proposed by NT Gas, but is the upper limit of the range considered appropriate by the Commission in light of new empirical evidence. The Commission is therefore of the view that its proposed market risk premium meets the interests of the service provider based on available empirical research.

The Commission will reconsider the appropriate level of the market risk premium over time as each regulatory decision is made and more empirical evidence becomes available.

Level of debt funding (gearing)

NT Gas suggested that the proportion of debt funding applicable to ABDP to be 50-60 per cent.[164] The Commission notes that the Modigliani-Miller theorem suggests that the relevant cost of capital should be invariant over a broad range of gearing possibilities. Therefore the gearing assumption used for WACC purposes should not be a critical one.[165] The Commission has tested alternative gearing ratios in its model and found these alternative values to have minimal impact on the final revenues and tariffs derived from the model.

The Commission notes Standard & Poors' most recent global financial projections for global power companies. Standard & Poors' estimate that the gearing ratio for global transmission and distribution power companies lies somewhere between 55 and 65 per cent.[166] Therefore, for the purpose of deriving the WACC for the ABDP, the Commission considers a gearing ratio of 60:40 to be reasonable. This gearing ratio is consistent with the Commission's other regulatory decisions.

The Commission is therefore of the view that, on balance, the proposed gearing ratio is consistent with the efficient provision of reference services under section 2.24(d) of the Code and with the legitimate commercial interests of the service provider under section 2.24(a). Furthermore, the Commission considers that the weight of available research and evidence, which is a relevant consideration under section 2.24(g) of the Code, supports the view that the proposed gearing ratio is appropriate.

Utilisation of imputation credits

The availability of tax imputation credits requires a modification to the standard CAPM/WACC model to reflect the return to shareholders of tax credits associated with their share dividends. Thus, gamma (γ) is included in the WACC calculation to represent the proportion of franking credits that can, on average, be used by shareholders of the company to offset tax payable on other income. The higher the gamma, the lower the required return to equity holders and therefore the lower the

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164 Access Arrangement Information, p. 26.

165 Modigliani and Miller establish that the value of the company is unaffected by its choice of capital structure using the principle of 'no arbitrage'. This principle states that assets that offer the same cash flows must sell for the same price. Thus, a company's borrowing decision does not affect either the expected return on the company's assets or the required return on those assets.

166 Standard and Poor's Rating Methodology for Global Power Companies, 1999, p. 4.

estimated WACC. Consequently, gamma becomes a significant parameter in the determination of financial returns.

NT Gas proposed a range of 25-50 per cent for gamma. The Commission's Victoria *Final Decision* and the *Draft Regulatory Principles* note that the analysis of imputation credits is a controversial issue and that there is considerable debate as to the value that should be ascribed. Ultimately, the Commission's choice of gamma will be a matter of judgement based on available empirical evidence.

The Commission has considered a range of 40 to 60 per cent appropriate for the average value of Australian input credits and has used 50 per cent for the value of gamma in all its decisions on gas access arrangements to date.

However, for regulatory purposes it is debatable whether an average for the value of imputation credits is appropriate. Generally, if an average rate is used in the regulatory rate of return investors who are able to take advantage of more than the average will receive a rate of return greater than their expected rate of return. As a consequence the company's share price will be bid up until the actual rate of return (based on the market value of the assets and not the regulated value) equals the required rate of return of those investors able to take the most advantage of the tax credits. Investors who are at a comparative disadvantage will either sell their shares or accept a lower rate of return. This argument tends to suggest that the appropriate value for utilisation of imputation credits for regulatory purposes should approach 100 per cent.

Furthermore, recent changes to Australia's taxation law[167] now means that Australian residents and complying superannuation funds that previously may not have been able to receive the full benefit of franking credits, can now do so.[168] This implies a gamma of 100 per cent for domestic investors.

In light of empirical evidence and recent changes to the tax system, the Commission is of the view that it might be more appropriate to set a gamma equal to one for regulatory purposes, assuming a private Australian ownership structure. However, uncertainty still remains regarding the appropriate value of gamma and until further research is undertaken, the Commission considers it appropriate to assume a gamma of 50 per cent in its *Final Decision* for the ABDP. The Commission notes that NT Gas agrees with the proposed gamma of 0.50.

Effective tax rate

Infrastructure owners are permitted to accelerate depreciation for tax purposes, hence tax depreciation may differ from economic depreciation. This difference between tax depreciation and economic depreciation means that there is an excess tax allowance in

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[167] On 30 June 2000 the New Business Tax System (miscellaneous) Bill 1999 received royal assent as Act 79.

[168] Resident individual investors receive the full benefit regardless of their tax position, as franking credits are now treated as a refundable rebate rather than as a tax deduction. Complying superannuation funds are preferentially taxed, which in the past, may have resulted in franking credits being eroded. Under the new tax system, franking credits are paid to the fund as a rebate from the Australian Tax Office.

the early years of a project or pipeline service, resulting in a considerable deferral of any tax liabilities associated with the project. These deferred liabilities serve to improve early cash flows to the investor and improve the internal rate of return of the project above that indicated by the assumed WACC parameters. This results in an effective tax rate for the return on equity (T_e) that is less than the statutory rate (T) assumed by NT Gas for the CAPM/WACC framework. The effective tax rate for NT Gas derived from the Commission's cash flow model is approximately 5.24 per cent.

In the CAPM/WACC equations there is an issue as to whether to use the statutory tax rate or the effective tax rate. This issue becomes irrelevant in the post-tax regulatory framework adopted by the Commission, as taxes are calculated on an 'as you go' basis. This involves using a post-tax WACC directly available from CAPM estimates to reflect the return on assets and to capture the impact of taxes in the cash flows. Such taxes are simply added, along with other capital costs and operations and maintenance costs, to calculate the target revenue requirement for the business. This approach avoids the need for a special conversion formula, which is discussed later, and handles tax in a very transparent way.

As the post-tax approach provides full compensation for actual tax liabilities as they occur, it avoids both the need to calculate a long-term effective tax rate and problems generated by post-tax returns diverging from market rates over time. As far as the business is concerned, the post-tax approach would remove any risks associated with future tax liabilities and provide a return commensurate with market requirements. This produces an outcome consistent with the legitimate interests of the service provider under section 2.24(a) of the Code.

To the extent that tax depreciation claimed in previous years may not have been fully exhausted in the reduction of tax liabilities, the amount will still be available (as a carried-forward tax loss) to reduce future taxable income. This carried-forward tax loss is calculated as the difference between depreciation for tax purposes (tax depreciation) and depreciation for accounting purposes (book depreciation) since 1986.

Identifying available tax concessions (as a carried-forward tax loss) in NT Gas's cash flows ensures that NT Gas receives an allowance for taxes over the access arrangement period in accordance with its (concession-inclusive) tax liability for the period.

Beta and risk

The risks faced by any business can be described as either systematic (non-diversifiable) or non-systematic (diversifiable).

Systematic risk is that risk that can not be eliminated through a well-balanced and diversified portfolio. This risk is generally market related and is measured with respect to the financial market as a whole. The CAPM provides for systematic (or non-diversifiable) risk through the equity beta, a statistical measure that indicates the riskiness of one asset or project relative to the whole market (usually taken to be the Australian stock market). The market average being equal to one, an equity beta of less than one indicates that the stock has a low systematic risk relative to the market as a whole. Conversely, an equity beta of more than one indicates that the stock has a relatively high risk.

Non-systematic risks are specific or unique to an asset or project and may include asset stranding, bad weather and operations risk. Such risks by their nature are specific and need to be assessed separately for each access arrangement. Importantly, specific risks are independent of the market. For an investor, exposure to the specific risk related to an asset can be reduced or countered by holding a diversified portfolio of investments. Consequently, investors do not require compensation for specific risks to be incorporated in the equity beta parameter of the CAPM.

A matter of significant debate in the Commission's assessment of the Victorian access arrangement was the treatment of specific (diversifiable) risk. At the time it was suggested that an allowance for specific risk could be accommodated via a higher beta in the CAPM formula. However, as noted above, the equity beta is meant to reflect only market related or non-diversifiable risks. Consistency with the CAPM framework therefore requires that specific risks be factored into projected cash flows rather than the cost of capital. For example, under the Commission's regulatory approach, specific risks relating to demand are compensated for through the use of forecast throughputs, rather than capacity, to calculate the reference tariff.

The Commission indicated in its *Draft Regulatory Principles* that this approach would normally be adopted with respect to identified and quantified specific risks.[169] This is consistent with the ORG's assessment, as stated in its first consultation paper for the 2003 review of gas access arrangements:

> … while events that are unique to particular businesses do not affect the cost of capital, they are not irrelevant. Rather, the price controls should be designed to ensure that the regulated entity expects to earns its cost of capital on average, taking account of all possible events.[170]

In its access arrangement information, NT Gas proposed an asset beta (β_a) range of 0.55–0.90 and an equity beta (β_e) range of 1.25-1.65. When calculating the equity beta NT Gas stated that it contrasted the results derived from the Monkhouse, Davis and CSFB formulas. Although the actual results of each of the calculations were not provided in the access arrangement information, NT Gas noted that the resulting equity betas 'were similar when identical inputs were used'.[171]

The Commission determined an asset beta for the ABDP of 0.50 in the *Draft Decision* and an equity beta of 1.16.

Asset beta

In response to the *Draft Decision*, NT Gas opposed the Commission's adoption of an asset beta of 0.50 and considered that an asset beta of 0.55 to 0.90 was more appropriate due to the risk of stranding on the pipeline and the smaller size and depth of the market served by the ABDP (as compared to the MAPS and Victorian gas transmission assets).

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[169] ACCC, *Draft Statement of Principles for the Regulation of Transmission Revenues*, 27 May 1999, p. 79.

[170] ORG, 2003 Review of Gas Access Arrangements, Consultation Paper No 1, p. 60.

[171] Access Arrangement Information, p. 28

The Commission notes the findings of a report prepared by Professor Kevin Davis for the South Australian Independent Pricing and Access Regulator (SAIPAR) on the WACC proposed by Envestra Limited for its distribution network in South Australia. Like NT Gas, Envestra argued for a higher WACC than that for the Victorian distribution network on the basis of slower market growth, a concentrated customer base resulting in greater variability of demand and greater competition from alternative fuel sources.[172]

Professor Davis considered that none of these arguments provided any rationale for assuming greater systematic (non-diversifiable) risk,[173] and concluded that there would appear to be no obvious reason to assume a higher asset beta for the South Australian market than for Victoria.[174]

Professor Davis also provided a response to Epic's submission on the Commission's MAPS *Draft Decision*. In this instance, Epic argued for a higher beta due to:

- the exposure of the MAPS to electricity generation load;
- the MAPS reliance on South Australia's few large industrial users, the majority of which are connected directly to MAPS; and
- the risk of bypass.[175]

In response, Professor Davis stated that:

> None of those listed [above] appear however to be relevant to assessing the systematic risk of the underlying asset (as opposed to its total risk). Unless cogent arguments can be advance that such factors affect the degree of co-variation between returns on the project and returns on the market portfolio, they are not relevant to determination of the asset beta. It is appropriate that, where relevant, such factors find reflection in the projections of expected demand used in the modelling approach to derive tariffs, or in arrangements for dealing with the possibility of asset stranding.[176]

Given this, the Commission did not consider it appropriate to compensate Epic for specific risk via a higher asset beta.

The Commission does not consider that the factors outlined by NT Gas impact on beta. While the markets served may be smaller than those of other pipeline systems, this by itself does not introduce a greater degree of systematic risk. In fact, risks to existing revenues are minimal due to the existence of long term contracts for the pipeline's capacity. The Commission also notes NTPG's submission that the foundation contract

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172 Envestra Limited, Access Arrangement Information for the South Australian Distribution System, 22 February 1999, Annexure B, p. 4.

173 Kevin Davis, The Weighted Average Cost of Capital for Access Arrangements for Envestra – A Report prepared for the SAIPAR, 20 October 1999, p. 7.

174 Kevin Davis, The Weighted Average Cost of Capital for Access Arrangements for Envestra – A Report prepared for the SAIPAR, 20 October 1999, p. 7.

175 Epic Energy, Response to Draft Decision – Part A, 10 October 2000, p.

176 Professor Davis, Report on Asset and Debt Beta for MAPS, 20 August 2001, p. 2.

is guaranteed by the Crown, which assures a revenue stream from commissioning of the ABDP, until 2011.[177]

The risk of asset stranding is not considered to be a systematic or non-diversifiable risk. Rather, it is a unique or specific risk, and as such, should be accommodated in the cash flows rather than the CAPM formula, it is the Commission's view that this approach is sound regulatory practice and therefore is a relevant consideration under section 2.24(g) of the Code.

The Commission also considers that the accelerated depreciation allowance provided for in the access arrangement substantially compensates NT Gas for the risk of stranding associated with the ABDP. It does this by providing a substantial return of capital to NT Gas by 2011 (excluding residual value). This mechanism provides protection of the legitimate interests of the service provider under section 2.24(a) of the Code. In view of these considerations, the Commission considers that an asset beta of 0.50 is appropriate for the ABDP.

In assessing the level of systematic risk facing the ABDP, the Commission has relied on a combination of empirical evidence and regulatory precedence in determining an asset beta of 0.50 for the ABDP.

A survey of US and UK asset betas was undertaken by the ORG as part of its *Electricity Distribution Price Determination 2001-2005*. The ORG estimated the average asset betas for proxy groups of companies in the UK, US and Australia.[178]

A recent study undertaken by NERA into international regulated rates of return found that asset betas set by regulators in the UK are consistent with the Commission's proposed asset beta of 0.50. NERA stated:

> Explicitly reported asset betas in the UK and those implicit (given assumed regulatory gearing ratios) would appear to be around or less than 0.5. This is consistent with the Australian average of 0.48.[179]

As part of his analysis of beta for the Commission, Professor Davis analysed beta information (published by Amex and Bloomberg) for utility companies listed on US stock exchanges described as having gas distribution/transmission activities. Professor Davis concluded from this analysis that an asset beta of 0.5 for the MAPS did not appear to be unreasonable.

With this empirical evidence in mind and an understanding of the complexities associated with comparing international asset betas, the Commission is of the view that an asset beta of 0.50 is appropriate for the ABDP. The Commission also notes that this is consistent with recent regulatory decisions in Australia. It is also the Commission's

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177 NTPG submission, 2 August 2001, p. 3.

178 Equity betas were provided by Bloomberg (US,UK, Aust), Ibbotson (US), the London Business School (UK) and the Australian Graduate School of Management Risk Measurement Service(Aust).

179 NERA, International Comparison of Utilities' Regulated Post Tax Rates of Return in: North America, the UK and Australia, March 2001, p.19.

view that consideration of available research and the conclusions that it reaches are a relevant consideration under section 2.24(g) of the Code.

Debt Beta

In its recent *Final Decision* for Victorian Gas Distribution businesses, the ESC undertook an investigation to provide further insight into the derivation of the debt beta valuation. It was concluded that the debt beta valuation is likely to be between 0.0 and 0.18, however a value toward the upper end of this range would be more appropriate.[180] The Allens Consulting Group (ACG) has also considered this information relating to the derivation of debt beta and concluded that an appropriate range for the debt beta would be between 0.0 and 0.15.[181] The Commission considers that an appropriate value for debt beta for this *Final Decision* would be towards the upper end of the findings of the ESC *Final Decision* and the ACG report and is therefore of the view that a debt beta of 0.15 is appropriate.

It is the Commission's view that its proposed debt beta reflects the latest available research on the estimation of debt beta in the Australian context. The Commission considers such information valuable in its consideration of these matters, and as such this information is a relevant factor to be taken into account when determining the debt beta for the ABDP, under section 2.24(g).

The Commission considers that a debt beta of 0.15 is appropriate in the circumstances of the ABDP.

The Commission provided a copy of the ACG report to Agility for comment. No response was received.

Equity Beta

In July 2002 the ACG undertook an assessment of beta for Australian gas transmission businesses.[182] Using data from the Australian Graduate School of Management, the ACG considered that the data imply an equity beta estimate of 0.7.[183] The ACG also considered data for comparable businesses in the US, Canada and UK. This analysis provided lower estimates of beta than that of Australian gas transmission businesses and supported the view that the estimate of 0.7 was not understated. The ACG stated:

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180 ESC, *Draft Decision: review of gas access arrangements*, July 20002, p. 231-233.

181 ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities*, Final report to the ACCC, July 20002, pp.28-29.

182 Allen Consulting Group, *Empirical evidence on proxy beta values for regulated gas transmission activities*, Final report for the ACCC, July 2002.

183 The result of 0.7 reflects calculations for the equity beta for Australian gas transmission businesses that result in a range of 0.66 to 0.69. The calculations assumed a debt:equity ratio of 60:40 and used data from AGL, Australian Pipeline Trust, Envestra and United Energy. Variables included excluding and including tax from the re-levering formula and a debt beta of either 0 or 0.15. Allen Consulting Group, *Empirical evidence on proxy beta values for regulated gas transmission activities*, Final report for the ACCC, July 2002, pp. 39-41.

> Exclusive reliance on the latest Australian market evidence would imply adopting a proxy equity beta (re-levered for the regulatory-standard gearing level) of 0.7 (rounded-up). Moreover, regard to evidence from North American or UK firms as a secondary source of information does not provide any rationale for believing that such a proxy beta would understate the beta risk of the regulated activities. Rather, the latest evidence from these markets would be more supportive of a view that the Australian estimates overstate the true betas for these activities.[184]

The ACG recommends that a conservative approach to beta estimation be retained by Australian regulators with the use of an equity beta estimate of one. The ACG notes:

> In the future, however, it should be possible for greater reliance to be placed upon market evidence when deriving a proxy beta for regulated Australian gas transmission activities.[185]

In the GasNet *Draft Decision*, the Commission considered that an asset beta of 0.5, and a debt beta of 0.15 was appropriate which produced an equity beta of 1.0.

Accordingly, via the application of the Monkhouse formula noted below, the Commission has determined an equity beta for the ABDP for this *Final Decision* of 1.0. This represents the absolute upper limit of a possible range for the equity beta suggested by the ACG analysis of available empirical evidence. It is the Commission's view that consideration of available empirical research and evidence is a relevant consideration under section 2.2.4(g) of the Code. This information assists the Commission to determine financial parameters with regard to the most up to date information available. The Commission has considered NT Gas' interests under section 2.24(a) of the Code by making a conservative adjustment to the equity beta to determine a value of 1.0 rather than 0.7 as indicated in the ACG report.

The Commission provided a copy of the ACG report to Agility for comment. No response was received.

Asymmetric risk and self insurance

In addition to outlining the additional risks it considers the ABDP faces, NT Gas has included margins for asymmetric risk and self insurance risk in its calculation of the nominal cost of equity.

NT Gas estimated a margin of 0.0-1.0 per cent for asymmetric risk and a margin of 0.0-0.5 per cent for self insurance costs. NT Gas did not provide further reasoning or empirical support for the proposed margins.

A similar adjustment to the cost of equity to allow for asymmetric risk and self insurance was proposed by AGLP in its CWP access arrangement. AGLP argued that it faced a significant asymmetry in specific risks and this should be reflected in a higher return. However, the Commission noted that while AGLP had drawn attention to its down-side risks, it had made comparatively little assessment of any upside benefits. In the case of the CWP, upside benefits included those available as a result of the

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184 Allen Consulting Group, *Empirical evidence on proxy beta values for regulated gas transmission activities*, Final report for the ACCC, July 2002, p. 42.

185 Allen Consulting Group, *Empirical evidence on proxy beta values for regulated gas transmission activities*, Final report for the ACCC, July 2002, p. 43.

incentive based arrangements operating in the regulatory framework and the reduction in the company tax rate from 36 per cent to 30 per cent.[186]

In the case of NT gas, the Commission acknowledges that because the ABDP is fully contracted there is minimal scope for NT Gas to grow the market (without augmentation of the pipeline). Consequently, upside benefits are most likely to arise as a result of achieving less than forecast operating and maintenance expenditure. However, while there may be little upside benefits available, the Commission believes that NT Gas faces virtually no downside risks. As the pipeline is fully contracted until 2011, there are minimal volume risks. Further, the Commission is proposing an accelerated depreciation schedule that provides a substantial return of pipeline capital to NT Gas by 2011.

On the issue of insurable risks, NT Gas states that the ABDP is subject to a higher level of natural and force majure style risks (eg. flooding, earthquake, lightening strikes) than many other pipelines and an allowance for self insurance cost should therefore be added to the cost of equity.

Many risks of the nature described by NT Gas are insurable and are captured as insurance premiums forming part of the operating and maintenance cost of the business. The Commission considers that, where those risks can be substantiated, compensation for self insurance risk, not already covered by insurance, should be quantified and included in the cash flows (as an operating cost) rather than as a premium in the WACC. The Commission would only consider it appropriate to incorporate an additional allowance for self insurance if it can be demonstrated that there are remaining risks which the service provider self insures against.

In its *Draft Decision*, the Commission did not include an allowance for self insurance in its cash flow analysis, however, it did provide NT Gas with the opportunity to supply further substantive and quantitative evidence to support its inclusion. NT Gas provided no further evidence to the Commission prior to the release of this *Final Decision* and therefore no allowance has been included in the cash flows for self insurance risk.

Calculation of the rate of return

Table 3.5 summarises the parameter values proposed by NT Gas in its access arrangement information and by the Commission in this *Final Decision*.

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[186] ACCC, 'Access Arrangement by AGL Pipelines (NSW) Pty Ltd for the Central West Pipeline', *Final Decision*, 30 June 2000, p.30.

Table 3.5: Comparison of WACC parameters used by NT Gas and Commission

CAPM parameter	NT Gas proposal	Commission *Draft Decision*	Commission *Final Decision*
Real risk-free rate (rr_f) %		2.98	3.26
Expected inflation rate (f) %	2.0-3.0	1.96	2.19
Nominal risk-free rate (r_f) %	5.5-5.9	5.00	5.52
Cost of debt margin (DM) %	1.0-1.40	1.20	1.54
Cost of debt (r_d) %	6.5-7.6	6.20	7.07
Real cost of debt (rr_d) %	n/a	4.16	4.78
Market risk premium (r_m-r_f) %	6.0-7.0	6.0	6.0
Debt funding (D/V) %	50-60	60	60
Usage of imputation credits (γ) %	25-50	50	50
Corporate tax rate (T) %	36	30	30
Effective tax rate (T_e)	36	1.53	5.24
Asset beta (β_a)	0.55-0.90	0.50	0.50
Debt beta (β_d)	n/a	0.06	0.15
Equity beta (β_e) [(a)]	1.25-1.65	1.16	1.0

Source: Access Arrangement Information, p. 26 and Commission analysis.

Note: (a) The Commission uses the Monkhouse formula as follows:

$$\beta_e = \beta_a + (\beta_a - \beta_d)(1 - r_d/(1+r_d)T_e).D/E.$$

This formula assumes an active debt policy aimed at maintaining a specific gearing ratio.

The parameter values used by the Commission are those considered most appropriate for the ABDP as a stand-alone business. These generally fall near the middle of a narrow range based on the information available.

NT Gas chose to convert the nominal post-tax WACC to a pre-tax WACC by first adjusting for tax then inflation. The Commission does not consider such an approach valid where the corporate tax rate is used. The conversion formula requires the use of an effective tax rate and the rate of inflation. These are both a source of uncertainty over the long term.

Table 3.6 below shows the WACC figures proposed by NT Gas in its access arrangement and the Commission in this *Final Decision*.

Table 3.6: WACC estimates based on parameters given in Table 3.5.

	per cent		
	NT Gas proposal	**Commission *Draft Decision***	**Commission *Final Decision***
Nominal cost of equity $r_e = r_f + \beta_e (r_m - r_f)$	14.3-17.3	11.96	11.67
Nominal pre-tax cost of debt (r_d)	6.7-7.4	6.20	7.07
Nominal vanilla WACC $W_n = r_e.E/V + r_d.D/V$	n/a	8.51	8.91
Post-tax nominal WACC $W = r_e [(1\text{-}Te)/(1\text{-}Te(1\text{-}\gamma))].E/V + r_d (1\text{-}T).D/V$	6.5-10.9	7.35	7.51
Post-tax real WACC $W_r = (1+W)/(1+f) - 1$	n/a	5.28	5.21
Pre-tax nominal WACC $W_t = r_e/(1\text{-}Te(1\text{-}\gamma)).E/V + r_d.D/V$	10.2-17.0	8.54	9.03
Pre-tax real WACC	8.5-11.7[(a)]	6.49[(b)]	6.75[(b)]
Pre-tax nominal WACC – cash flows (W_{trci})	n/a	8.59[(b)]	9.09[(b)]
Implied tax wedge $= W_{trci} - W_n$	n/a	0.08	0.18

Source: Access Arrangement Information, p. 26 and Commission analysis.

Note: (a) calculated by NT Gas using the forward transformation formula: $W_{tr} = (1+W_t)/(1+f)-1$
(b) obtained from the Commission's cash flow analysis.

In calculating the post-tax revenue requirement that is consistent with the nominal cost of equity established by the CAPM, the return on capital has been calculated using the nominal vanilla WACC. Taxes have been addressed specifically in the cash flows as they arise.

The nominal vanilla WACC can be defined as the weighted-average cost of debt and equity before any adjustments for tax and inflation. In other words, it represents the most basic post-tax return required by the business after all costs have been paid. That is it covers the post-tax cash flow required by equity holders and interest payments on debt.

The difference between the nominal pre-tax WACC and the nominal vanilla (post-tax) WACC is represented by the 'tax wedge'. The tax wedge has been used by the Commission to normalise tax payments over the life of the assets. This approach is discussed below in section 3.7.5.

Given the known shortcomings of the conversion formulae, the Commission has replicated the post-tax cash flows in a pre-tax framework to find the pre-tax real WACC that is consistent with the nominal cost of equity.

The Commission has found that a pre-tax real WACC of 6.75 per cent is consistent with a post-tax nominal cost of equity of 11.67 per cent.

While 11.67 per cent is the expected post-tax cost of equity under the assumptions of the regulatory framework, this is a long-term expectation. In reality, returns may vary from year to year and can be expected to exceed this benchmark under the incentive provisions of the access arrangement.

Therefore, while the Commission notes NT Gas' comments that the rate of return is low, the proposed post tax cost of equity is a benchmark rate that the service provider can outperform. Such an outcome would be in the legitimate interests of the service provider and would further contribute to the efficient operation of the pipeline under section 2.24(a) and (d) of the Code.

In contrast, Woodside asserted that a pre tax WACC of 11 percent was the driver of unrealistic reference tariffs. The Commission notes that the post-tax return on equity has been derived based upon WACC parameters that the Commission has determined as balancing the interests of the service provider and users, takes into account the most recent research on relevant matters and other pertinent considerations. As the various components of the WACC have been reconciled with the relevant provisions of section 2.24, the Commission does not agree that the proposed post-tax nominal return on equity is of detriment to users.

Given the resulting scope for variation between the key rates of return, it is important to note the assumptions made to arrive at the Commission's outcome. The model used is strictly in line with the regulatory framework proposed by the Commission. Post-tax cash flows have been assessed over the remaining life of the ABDP, that is, 65 years. Asset values, operating and maintenance costs, capital expenditure and financial parameters are as specified in this *Final Decision*. Capital expenditure beyond the access arrangement period has not been included in the model because the Code requires the Commission to set a rate of return on the value of the assets that form the covered pipeline (capital base), that is, on the value of the existing assets plus capital expenditure during the access arrangement period.[187] The Commission has used NT Gas' forecast operating and maintenance costs until 2011 and indexed operating and maintenance costs by the estimated rate of inflation thereafter. The Commission has also included an additional cost component in the cash-flow analysis, which it had not been notified of at the time of releasing the *Draft Decision*. The basis for this parameter reflects pre-existing contractual commitments which are considered confidential and are discussed in more detail in section 3.3.6 and Confidential Annexure E.

Amendment FDA3.5

In order for NT Gas' access arrangement for the ABDP to be approved:

- the WACC estimates and associated parameters forming part of the access arrangement and access arrangement information must be amended to reflect the current financial market settings by adopting the parameters set out by the Commission in Table 3.5 and Table 3.6; and
- the target revenues and forecast revenues must be based on these new parameters.

[187] Code section 8.4(a).

3.5 Non-capital costs

3.5.1 Code requirements

The Code (sections 8.36 and 8.37) allows for recovery of the operating, maintenance and other non-capital costs that a prudent service provider, acting efficiently and in accordance with good industry practice, would incur in providing the reference service.

Attachment A to the Code requires the service provider to disclose certain costs in the access arrangement information, unless it would be unduly harmful to the legitimate business interests of the service provider, a user or a prospective user. The costs to be disclosed include those for wages and salaries, contract services including rental equipment, materials and supply and corporate overheads and marketing. The service provider must disclose gas used in operations. Some disaggregation by zones, services or categories of assets is also required.

3.5.2 NT Gas' proposal

Subsequent to the *Draft Decision*, NT Gas submitted revised operating costs estimates, consistent with a 10 year access arrangement period, as given in Table 3.7 below.

Table 3.7: Total Operating Costs 2002-2011

Year Ending June 30 ($'000)	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Operations & maintenance	5,347	5,644	7,193	6,633	6,570	7,609	6,957	7,944	7,418	7,710
Administration & general	1,351	1,383	1,145	1,449	1,483	1,518	1,554	1,591	1,628	1,667
Sales & Marketing	138	141	145	148	152	156	160	164	168	172
Total Operating Costs	**6,836**	**7,168**	**8,753**	**8,230**	**8,205**	**9,283**	**8,670**	**9,699**	**9,214**	**9,549**
Original submission	**7,191**	**7,298**	**7,521**							
Variance	**(355)**	**(130)**	**1,232**							

Source: Facsimile from Agility, 5 June 2002, p.2.

All of the operating and maintenance costs are direct costs and are to be recovered from reference tariffs on the basis of length of pipeline operated in each of the three pricing zones. Administration and general costs are allocated on the same basis, while sales and marketing costs are allocated on the basis of the quantity of gas delivered.[188]

Compared to NT Gas' previously forecast total operating costs, there has been a decline in expenditure for 2002 and 2003 which is attributable to efficiency savings and the deferral of pigging until 2004. The increase in proposed expenditure for 2004 is more than previously forecast and is the result of rescheduled pigging activities.[189]

188 Access Arrangement Information, p. 35.

189 Facsimile from Agility to the Commission, 5 June 2002, p.2.

3.5.3 Commission's *Draft Decision*

Based on a comparison of NT Gas' key performance indicators (KPIs) with other transmission pipelines, the Commission concluded that NT Gas' forecast operating and maintenance costs were not unreasonable.

3.5.4 Submissions by interested parties

In its joint submission on the Issues Paper, the NT Government and PWC noted that operating costs have 'been a bone of contention' between PWC and NT Gas since 1986.[190] In particular:

> ...NT Gas' operations and maintenance costs for the Pipeline are unreasonable and do not represent the efficient costs of delivering the reference service in accordance with global best practice.[191]

NTPG accepted the Commission's findings in the *Draft Decision* that the estimates for non-capital costs are reasonable given the lower levels of throughput experienced in 2000/01.[192]

3.5.5 Commission's consideration

Two industry accepted benchmarks for operations and maintenance costs are cost per pipeline length and cost per volume transmitted. Comparisons between the ABDP and other transmission pipelines in Australia are shown in Table 3.8 below. In terms of $/1 000km, the ABDP compares favourably with the other pipelines. However, in terms of $/GJ, the ABDP appears to be more expensive to operate than other pipelines.

It must be noted that while these measures of pipeline cost efficiency have been accepted in the industry, they do have limitations. The comparisons can be made, but in doing so other aspects of the pipelines such as compression, age and throughput should generally be noted.

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[190] NT and PWC Submission, 17 November 1999, p. 8.

[191] NT and PWC Submission, 17 November 1999, p. 8.

[192] NTPG Submission, 2 August 2001, p. 4.

Table 3.8: Comparison of transmission pipeline non-capital costs

	$/1 000km ($m)	**$/GJ**
NT Gas – ABDP (2001)	4.1[c]	0.42[d]
EAPL – MSP (2001)[a]	6.1	0.12
Epic – Moomba-Adelaide Pipeline (1999)[b]	19.2	0.16
TPA – Victorian transmission systems (1998)	16.0	0.13
AGLP – CWP (1999)[e]	2.8	2.62
AGLP – CWP (2004)[e]	2.8	0.52

Notes: (a) EAPL, Proposed Access Arrangement Information, p. 65.
(b) Epic, Proposed Access Arrangement Information, attachments 1 & 4.
(c) Based on total operating costs for 2001/02 ($6.8m) divided by pipeline length (1649km).
(d) Total operating costs for 2001/2002 divided by total throughput (16.4PJ).
(e) AGLP, Revised Access Arrangement Information, pp. 27-31. 2004 figures based on forecast throughputs.

The higher $/GJ measure calculated for NT Gas may be attributed to the differences in capacity/throughput between the pipelines and the subsequent economies of scales inherent in larger capacity pipelines. For example, while both the ABDP and MAPS are fully contracted, the current firm capacity for each of the pipelines is approximately 54 TJ and 323 TJ[193] per day respectively.

Another measure that is sometimes employed is to determine forecast operating costs as a percentage of the overall capital assets employed.[194] Typically, results range from 2 per cent for an uncompressed pipeline to 5 per cent for a fully compressed pipeline. In NT Gas' case, forecast operating costs are approximately 1.8 per cent of the ORC value calculated by the Commission. On this measure, the Commission considers NT Gas' forecast costs to be reasonable, as did NTPG. The Commission notes PWC's comments regarding NT Gas' cost of delivering services.

The Commission is of the view that the proposed non-capital costs are not unreasonable and are not contrary to the interests of users and potential users under section 2.24(f) of the Code. The Commission has considered whether the proposed non-capital costs represent the legitimate business interests of the service provider and are necessary for the safe and reliable operation of the ABDP under sections 2.24(a) and (c) of the Code. The Commission is also of the view that the revised operating costs (as per Table 3.7) satisfy the requirements of section 2.24(d) of the Code.

Chapter 5 of this *Final Decision* discusses the use of KPIs and performance benchmarks in more detail. It concludes that, on the basis of the available information and KPIs, the operating, maintenance and other non-capital costs for the ABDP are not unreasonable.

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193 Epic Energy's Access Arrangement Information for MAPS, p. 11.

194 In the interests of comparison between pipeline systems, the ORC figure may be used as a measure of the value of the capital assets employed.

3.6 Legitimate business interests and existing contractual obligations

3.6.1 Code requirements

Section 2.24 of the Code requires the regulator to take into account the following matters when assessing an access arrangement:

(a) the service provider's legitimate interests and investment in the pipeline;

(b) firm and binding contractual obligations of the service provider or other persons (or both) already using the pipeline;

(c) the operational and technical requirements necessary for the safe and reliable operation of the pipeline;

(d) the economically efficient operation of the pipeline;

(e) the public interest, including the public interest in having competition in markets (whether or not in Australia);

(f) the interests of users and prospective users; and

(g) any other matters that the regulator considers relevant.

With regards to the reference tariff section 8.1 of the Code requires that the reference tariff policy be designed with a view to achieving the following:

(a) providing the service provider with the opportunity to earn a stream of revenue that recovers the efficient costs of service;

(b) replicating the outcome of a competitive market;

(c) ensuring the safe and reliable operation of the pipeline;

(d) not distorting investment decisions in pipeline transportation systems or in upstream and downstream industries;

(e) efficiency in the level and structure of the reference tariff; and

(f) providing an incentive to the service provider to reduce costs and to develop the market for reference and other services.

Section 8.1 further states that, to the extent that any of these objectives conflict in their application to a particular reference tariff policy and reference tariff determination, the regulator may determine the manner in which they can best be reconciled or which of them should prevail by reference to the criteria contained within section 2.24.

3.6.2 Submissions from interested parties

In its submission, the NT Government stated that:

> The introduction of the proposed reference tariff, which is materially lower than the foundation customer arrangements, operates contrary to the objective set out in clause 8.1 [of the Code]. Specifically, the principles set out in clause 8.1(a) require an ex ante assessment of the stream of revenue to cover efficient costs. It is not appropriate to carry out that assessment on an ex post basis … there are real questions about the extent of the utilisation of the pipeline for forward haulage beyond the term of the long term agreement which ends in 2011. In these circumstances, the starting point for the ACCC's assessment of the recovery of efficient costs should be the price under the foundation contract.[195]

The NT Government further stated that a tariff structure that sets the reference tariff below the foundation customer contract provides no incentive for foundation customers to enter similar long term agreements and had the significant prospect of deterring, or delaying investment in required pipelines.[196]

The NT Government also claimed that the imposition of the ACCC's reference tariff had the potential to leave PWC's assets stranded, the cost of which would be borne by electricity consumers and the Territory tax payers.[197]

3.6.3 NT Gas' response to the *Draft Decision*

NT Gas provided a response to this issue on a confidential basis.

3.6.4 Commission's considerations

Following the release of the *Draft Decision*, the Commission sought further information from NT Gas' regarding its total costs and tariffs currently paid by users on the pipeline. This information revealed two additional cost components of which the Commission was previously unaware and demonstrated that the revenues determined under the *Draft Decision* were insufficient to cover NT Gas' total costs.

The Commission considers that one of these cost components should appropriately be provided for as a capital cost and has been reflected in the ICB valuation. Compensation for the other cost component is provided for through inclusion in the cost of service model to determine annual cash flow requirements. The notification of these costs to the Commission has assisted in alleviating some of the discrepancy between NT Gas' costs and total regulated revenues.

The Commission considers that these payments represent legitimate costs to NT Gas and failure to include it in the building block approach could result in an adverse effect on NT Gas and downstream markets.

The Commission considers that the principles set out in sections 8.1(a) and (b) and sections 2.24 (a),(b), (e) and (f) of the Code would not be met if NT Gas was unable to earn sufficient revenue to meets its obligations under the lease and other agreements. Therefore, the Commission has included an allowance in the calculation of total revenue to compensate NT Gas for the additional cost components. Given the

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195 NT Government submission, 4 October 2001, p. 5.

196 NT Government submission, 4 October 2001, pp. 5-6.

197 NT Government submission, 4 October 2001, p. 9.

confidential basis for these costs they are discussed in greater detail in Confidential Annexures D and E.

Amendment FD3.6

In order for NT Gas' access arrangement to be approved, allowances for the additional tariff component (as detailed in Table D.1 of Confidential Annexure D) must be included in the calculation of forecast revenues.

3.7 Forecast revenue and pipeline capacity

3.7.1 Code requirements

As noted previously, the Code (section 8.4) sets out three alternative methodologies for determining total revenue. In this access arrangement, the service provider has proposed to use a cost of service methodology. Total revenue is calculated as the return on the value of the capital base, depreciation of the capital base plus the operating and maintenance and other non-capital costs incurred in providing its services over the covered pipeline.

3.7.2 NT Gas' proposal

NT Gas submitted that it did not anticipate that any revenue would be generated from the sale of the reference service or negotiated service during the access arrangement period, as the capacity of the ABDP is fully committed to users under pre-existing transportation contracts.[198] Furthermore, NT Gas contended that the revenue earned by NT Gas under those pre-existing contracts is less than the total revenue NT Gas is likely to be entitled to recover under the Code.[199]

NT Gas also considered that there was great uncertainty regarding the usage of, and hence revenue from, the rebatable service and therefore made no provision for this in its forecast of total revenue. NT Gas' forecasts for total revenue reflect the amounts to be generated from selling current contracted throughput at the proposed reference tariffs over the access arrangement period. This is provided in Table 3.9 below.

[198] Access Arrangement Information, p. 30.

[199] Access Arrangement Information, p. 30.

Table 3.9: Forecast revenue, NT Gas proposal, 2000 to 2004

	Forecast revenue ($m)	
Year ending 30 June	**Real dollars[(a)]**	**Nominal dollars**
2000	52.7	54.0
2001	52.1	53.4
2002	52.0	53.3
2003	51.6	52.9
2004	51.5	52.8

Source: ACCC calculations from data in the Access Arrangement Information, p.30.
Note: (a) assumes an inflation rate of 2.5 per cent.

NT Gas was also given the opportunity to respond to NTPG's submission (discussed below) that PWC is required to fund a second compressor station. NT Gas stated:[200]

> Where a party (including PWC) has capacity requirements which require an additional compressor, that party will be responsible for funding the installation of the compressor. In respect of any obligation which may exist under the Gas Sales Agreement for PWC to fund another compressor, this is a confidential contractual matter between NT Gas and PWC and is not an appropriate matter for third parties to seek to enforce through the access arrangement.

3.7.3 Commission's *Draft Decision*

Based on the its proposed amendment to WACC, inflation and tariffs, the Commission calculated NT Gas' forecast revenues as given in Table 3.10 below.

Table 3.10: *Draft Decision's* Forecast revenue for 2002 to 2006

Year ending 30 June	Forecast revenue ($m)
2002	29.9
2003	29.6
2004	30.2
2005	30.1
2006	29.9

Source: ACCC calculations.

3.7.4 Submissions from interested parties

Submissions to the Issues Paper

PWC noted that the statements made by NT Gas are consistent with PWC's understanding that there is no firm capacity presently available on the pipeline without further compression.[201] PWC also submitted that although there is likely to be some

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200 Email from Agility Management, on behalf of NT Gas, to Commission staff, 27 March 2001.

201 NT and PWC Submission, 17 November 1999, p. 3.

interruptible capacity available, given that the significant current market for gas in the NT is for electricity generation, peak gas and electricity demand periods are likely to be the same for most users.[202]

NTPG submitted that the existing lease obligations provide for PWC (the foundation customer) to fund an adequately sized second compressor. NTPG claimed that if an additional compressor were installed, then extra capacity would be made available for sale under the reference service tariff during the access arrangement period. NTPG also suggested that failure to install the second compressor would represent a strategic move by PWC to lessen potential competition in the electricity industry.[203]

NTPG contended that:

> were ABDP pipeline capacity actually to become a significant factor preventing the sale of the Reference Service, it would be the consequence of NT Gas choosing not to request PWC's installation of additional compressor capacity on a timely basis. Such a scenario of events would be consistent with PWC's apparent strategic business interest in creating barriers to entry for potential competitors in the electricity industry.[204]

In reply, PWC rejected that it has any immediate obligation to fund another compressor.[205]

Submissions to the Draft Decision

NTPG considered the revenue determined by the Commission is fair and equitable for all stakeholders in the ABDP. However, NTPG vigorously disputed NT Gas' assertion that the capacity of the ABDP is fully contracted until 2011.[206]

NTPG stated that the highest level of gas shipments (approximately 4.6PJ) on the ABDP to date took place in the October-December quarter of 1999 suggesting an annual capacity of about 18PJ existed at that time.

NTPG further stated:

> NT Gas access arrangement information of 25 June suggests a maximum delivery rate with one compressor of 54 TJ/day. This suggests approximately 20PJ existing annual capacity.[207]

3.7.5 Commission's considerations

NT Gas applied a cost of service framework to determine total revenue as permitted by section 8.4 of the Code.

As a result of the Commission's amendments proposed for the ICB, WACC, inflation, additional cost component and tariffs, the forecast regulated revenue path for the ABDP

202 NT and PWC Submission, 17 November 1999, p. 3.

203 NTPG submission, 12 September 1999, p. 6.

204 NTPG submission, 12 September 1999, p. 6.

205 NT and PWC Submission to, 17 November 1999, p. 3.

206 NTPG submission, 2 August 2001, p. 4.

207 NTPG submission, 2 August 2001, p. 4.

will be different to that proposed by NT Gas. The forecast revenues resulting from the Commission's analysis are provided in Table 3.11 below.

Table 3.11: Commission's *Final Decision* forecast revenue for 2002 to 20011

Year ending 30 June	Forecast revenue (nominal $m)
2002	45.08
2003	45.35
2004	46.81
2005	47.12
2006	47.42
2007	47.73
2008	35.55
2009	35.78
2010	36.01
2011	36.24

Source: ACCC calculations.

According to NT Gas, the ABDP currently has no available firm capacity and only a small amount of interruptible capacity. Given this, NT Gas is expected to earn its revenues primarily from it existing haulage agreements, with little or no revenue accruing from negotiable or interruptible services. The Commission has assessed NT Gas' total revenue for the purposes of section 8.2 of the Code based upon forecast firm capacity.

Existing capacity of the ABDP

The Commission notes that some confusion has arisen over the existing capacity of the ABDP. This confusion may have arisen due to the misinterpretation of statements made in NT Gas' access arrangement information. The access arrangement information states that the annual volume on the ABDP is 16PJ and the pipeline is fully contracted until 2011,[208] however, further examination of the information reveals that the maximum delivery capacity of the pipeline is 54 TJ/day[209] (which is approximately equivalent to 19.7 PJ/year). Therefore, while only 16 PJ/year (44 TJ/day) is currently shipped on the pipeline, the capacity of the ABDP is 54 TJ/day, all of which NT Gas claims is fully contracted to existing users.

Despite the conjecture over existing capacity, the Commission has obtained copies of NT Gas' existing contracts and most recent capacity report and confirms that the capacity of the pipeline is 54TJ/day which, given current MDQ nominations, is fully contracted until 2011.

[208] Access Arrangement Information, p. 2.

[209] Access Arrangement Information, p. 39.

Normalisation of tax payments and 'CPI-X' revenue smoothing

In establishing the cost of service revenue requirement, the Commission has normalised NT Gas' tax payments over the life cycle of the asset to remove the 's-bend' phenomenon.[210] The objective of normalisation is to ensure that customers do not, as the result of higher tax payments that will need to be made at a later period, have to pay a disproportionately higher charge for services produced by the assets at that time. It is the Commission's view that normalisation of the ABDP's revenues is in the interests of users and prospective users under section 2.24(f) of the Code, by alleviating any tariff shocks due to the occurence of taxation expenses at a later date. A potential tariff shock may lead to distortions in the reference tariff and could therefore be contrary to the promotion of competition in related markets and the interests of users under sections 2.24(e) and (f) of the Code.

To normalise tax liabilities the Commission has included in the post-tax revenue requirement a factor that, in effect, represents additional depreciation (return of capital) that accumulates initially and subsequently reduces when taxes become payable and enter the cash flows. This allowance is calculated as the tax wedge[211] multiplied by the asset base less the net tax liability in each year. This ensures that when taxes enter the cash flows there is no sudden increase in the revenue requirement and therefore reference tariff. A more detailed discussion of normalisation can be found in section 2.7.4 of the *Draft Decision*. The normalisation process is not contrary to the interests of NT Gas under section 2.24(a) of the Code, as on an NPV basis the service provider will receive the same amount of revenue.

As discussed later in section 3.9.5, the Commission has calculated a smoothed tariff path for each of the three zones during the access arrangement period. The total forecast revenue shown in Table 3.11, is based on the smooth tariff path set out in Table 3.14 (section 3.9.5) and NT Gas' volume forecasts for the access arrangement period. Amendments in this *Final Decision* results in a regulated revenue stream over the access arrangement period that is less than that proposed by NT Gas.

3.8 Cost allocation and tariff setting

3.8.1 Code requirements

Section 8.38 of the Code requires that, to the maximum extent that is commercially and technically reasonable, reference tariffs should recover all costs directly attributable to the reference service and a fair and reasonable share of joint costs. The Code (section 8.42) requires that a particular user's share of reference service revenues recover costs according to the same principles.

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210 A detailed discussion of the 's-bend' problem is provided in Attachment B to ACCC, 'NSW and ACT Transmission Network Revenue Caps 1999/00 – 2003/04', *Final Decision*, January 2000, and Attachment C to ACCC, 'Access Arrangement by AGC, Pipelines (NSW) Pty Ltd for the Central West Pipeline, *Final Decision*, June 2000.

211 Equal to the difference between the nominal vanilla WACC and the nominal pre-tax WACC that has been derived from the Commission's cash flow analysis.

3.8.2 NT Gas' proposal

In its access arrangement, NT Gas stated that tariffs would be charged on the basis of throughput, that is $/GJ of throughput. However, NT Gas access arrangement states that where the quantity of gas transported for a user is less than 80 per cent of the annual contract quantity (ACQ) in a contract year, the user will pay an amount equal to the charge for delivery of 80 per cent of ACQ in that contract year.[212]

NT Gas proposed to allocate total revenue across the following 3 pricing zones:

Zone 1 – Amadeus Basin to Warrego (730 km)

Zone 2 – Warrego to Mataranka (521 km)

Zone 3 – Mataranka to Darwin (407 km)

Total operating costs were generally allocated to each zone on the basis of length of pipeline operated in each zone. The return on capital and return of capital (depreciation) are allocated on the basis of the proportion that the ORC of pipeline assets in each zone bears to the total ABDP ORC as at 30 June 1999.

NT Gas claimed that the introduction of zonal pricing is an attempt to develop the market for pipeline services and to replicate the outcomes of a competitive market. Under the proposed tariff structure, receipt and delivery of gas to any point within a zone is charged at the throughput tariff applicable to that zone. Should gas be transported across two or more zones, then the throughput charge is the sum of the relevant throughput tariffs for each of those zones.[213]

NT Gas considered that the adoption of zonal tariffs is more cost-reflective of a user's utilisation of the pipeline than a single postage stamp tariff (existing), while avoiding the complexities and expense of administering a strictly distance based tariff.[214]

3.8.3 Commission's *Draft Decision*

The Commission proposed the following amendment to NT Gas' access arrangement:

Proposed Amendment A2.7

In order for NT Gas' access arrangement for the ABDP to be approved, the ORC valuations for each zone used for the calculation of tariffs should be amended as follows:

Zone One	$147.2m
Zone Two	$100.1m
Zone Three	$75.0m

212 Access Arrangement, p. 11.

213 Access Arrangement Information, p. 7.

214 Access Arrangement Information, p. 7.

3.8.4 Submissions from interested parties

Santos pointed out that under a zonal pricing structure the same tariff applies for gas transportation 407km from Mataranka to Darwin as would apply for a much shorter section from an injection point near Darwin. Santos noted that in the case of a Petrel Tern development, where one concept would involve connection to the ABDP close to Darwin, such a tariff proposal would have a significant negative impact upon project cash flows.[215]

Santos considered that the best solution would be to for the access arrangement to propose a tariff on a $/GJ/km basis. Santos stated:

> Zonal tariffs do not provide maximum flexibility and will potentially create a disincentive for the development of new projects and for the use of the ABDP for Timor Sea gas. This could give rise to the potential stranding of the ABDP.[216]

Santos recognised that under the existing supply source and customer base, the practical difference between distance and zonal pricing was likely to be minimal. However, Santos considered that this may not be the case as Timor Sea projects are developed, and resolving distance inequalities at this point in time would ensure that the access arrangement is better placed to deal with new developments and the entry of Timor Gas.[217]

NTPG stated that it accepted the *Draft Decision's* approval of zonal pricing.[218]

3.8.5 NT Gas' response to the *Draft Decision*

NT Gas stated that it did not object to the Commission's amendment that ORC valuations used to allocate costs to each tariff zone be amended to reflect the Commission's estimate of ORC.

3.8.6 Commission considerations

Tariff Structure

The Commission notes that existing contracts on the ABDP incorporate a 'postage-stamp' tariff, that is, a single tariff applies for receipt and delivery of gas at any point along the pipeline. NT Gas considered that potential users most affected by postage stamp pricing are those with price sensitive projects located part way along the pipeline, which would be charged for delivery of gas as if that gas was transported the entire length of the pipeline.[219]

The zonal tariff structure proposed by NT Gas creates three postage stamp tariffs in the place of the existing single tariff, with gas transportation charges varying between each

215 Santos submission, 8 June 2001, pp. 2–3.

216 Santos submission, 8 June 2001, p. 3.

217 Santos submission, 8 June 2001, p. 3.

218 NTPG submission, 2 August 2001, p. 5.

219 Access Arrangement, p.6.

zone. Thus, two customers in the same zone would still pay the same price, regardless of the distance gas is transported within that zone.

While the Commission considers zonal tariffs an improvement on postage stamp pricing, zonal pricing still has the potential to result in inefficient pricing signals. As noted by Santos, the same tariff would apply for the transportation of gas 407km from Mataranka to Darwin as would apply for a much shorter section from an injection point near Darwin.[220]

Generally, the Commission considers that distance based tariffs are the most efficient means of charging for gas transportation. However, when making its assessment the Commission must weigh the benefits of distance based tariffs against the additional costs of determining and administering a distance based pricing regime. It is the Commission's view that minimising regulatory compliance costs is a relevant criteria under section 2.24(g) of the Code, provided it is not contrary to the interests of the service provider or users.

The Commission and Santos note that given the majority of the ABDP's customers are located towards the end of the pipeline, the practical difference between distance based pricing and zonal pricing is likely to be minimal. The use of zonal pricing is unlikely to distort access to the pipeline and negatively effect competition in related markets. Such an outcome would not be contrary to the interests of users and potential users under section 2.24(e) of the Code.

Consequently, the *Draft Decision* approved a zonal pricing structure for the ABDP. However, further comment was sought from interested parties regarding the potential benefits and costs associated with distance based pricing for consideration in the *Final Decision*.

Santos was the only interested party to raise an objection to the *Draft Decision's* approval of zonal pricing. Santos agreed that under the existing supply source and customer base the difference between zonal and distance based pricing was likely to be minimal. However, Santos argued that this may no longer be the case as Timor Sea projects are developed.[221]

As discussed in section 3.3.6, the Commission considers that there is a reasonable likelihood that Timor Sea gas will be onshore sometime in the future. However, it is still difficult to determine when such an event is likely to actually occur, and to what extent it might involve the use of the ABDP. Given this uncertainty and the likelihood that the reference tariff will not be available, or only available to a limited extent, during the access arrangement period the Commission considers that a move to distance based pricing is unnecessarily complicated. The circumstances of the ABDP represent a relevant consideration to be taken into account when considering the application of zonal tariffs, under section 2.24(g) of the Code.

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220 Santos submission, 8 June 2001, pp. 2 – 3.

221 Santos submission, 8 June 2001, p. 3.

It should also be noted that the presence of a zonal reference tariff does not preclude the negotiation of a distance based tariff or discounts to the reference tariff due to the short shipping distance. It is the Commission's view that this option provides for the interests of users and prospective users under section 2.24(f) of the Code.

Should gas production development occur during the life of the access arrangement, the inclusion of a review trigger would be likely to be activated. If such an event were to occur the Commission could consider modifying the tariff structure to reflect any new market environment. It is the Commission's view that the inclusion of a trigger mechanism provides scope to protect the legitimate interests of users and prospective users under section 2.24(f) of the Code.

Therefore, the Commission considers that for the purposes of this access arrangement, zonal pricing is a reasonable methodology for determining tariffs for the ABDP. The Commission will re-examine this issue in subsequent access arrangements.

Allocation of costs

In determining its proposed tariff schedule the Commission used the same methodology as NT Gas for the allocation of costs to each zone. Under this approach:

- sales and marketing costs are allocated based on the quantity of gas delivered in each zone;
- all other operating costs are allocated based on pipeline length; and
- return on capital and return of capital are allocated on the proportion of ORC the pipeline assets in each zone represents in relation to the total ORC.

In calculating the tariffs the Commission has utilised its own estimates of ORC for the pipeline assets in each zone, resulting in slightly different ORC proportions for Zone One and Zone Three. This leads to an increase in Zone One and Zone Two tariffs. The Commission considers that every effort should be made to ensure that the tariffs are consistent with the new ORC valuation, and are as cost reflective as possible.

Amendment FDA3.7

In order for NT Gas' access arrangement for the ABDP to be approved, the ORC valuations for each zone used for the calculation of tariffs should be amended as follows:

Zone One	$171.6m
Zone Two	$118.6.m
Zone Three	$83.5m

A breakdown of the ORC valuations for each Zone can be found in Annexure B of this *Final Decision*.

3.9 Tariff path and incentive structure

3.9.1 Code requirements

The Code (section 8.3) gives discretion to service providers as to how reference tariffs may be varied during an access arrangement period. For example, tariffs may change according to a 'price path' approach where tariffs follow a path determined at the start of the period. The alternative method specified in the Code is the 'cost of service' approach. Under this approach, tariffs are set according to forecast costs and are adjusted throughout the access arrangement period in light of actual outcomes. The Code also allows variations or combinations of the approaches to be used.

Where the regulator considers it appropriate, section 8.44 of the Code provides for the regulator to require or approve an incentive mechanism. Such a mechanism enables a service provider to retain all or a share of any returns from the sale of a reference service that exceeds the level expected at the beginning of the access arrangement period. This mechanism operates particularly where the increased returns are attributable, at least in part, to the service provider's efforts. This incentive mechanism should encourage the service provider to increase sales volumes, minimise costs, develop new services, and undertake only prudent investment (section 8.46). The mechanism should be designed to ensure that users gain from any increased efficiency, innovation and improved sales volumes. The mechanism may include:

- specifying that tariffs are based on forecast, not realised, values of variables;
- setting a target revenue and specifying how revenue in excess of this is to be shared between the service provider and users; and
- establishing a rebate mechanism for rebatable services that does not provide a full rebate to users.

Sections 8.47 and 8.48 of the Code allow a reference tariff policy to include certain principles that remain fixed for a set period (referred to as the 'fixed period'). These fixed principles can not be changed without the agreement of the service provider and may only include structural elements and not 'market variable' elements.

While a fixed period may apply for all or part of the duration of an access arrangement, the regulator is required to consider the interests of users and prospective users in determining the period.

Section 10.8 of the Code defines a market variable element as:

> … a factor that has a value assumed in the calculation of a Reference Tariff, where the value of that factor will vary with changing market conditions during the Access Arrangement Period or in future Access Arrangement Periods, and includes the sales or forecast sales of Services, any index used to estimate the general price level, real interest rates, Non Capital Cost and any costs in the nature of capital costs.

3.9.2 NT Gas' proposal

Reference tariffs

As shown in Table 3.12, NT Gas proposed a set of 'smoothed' reference tariffs applicable to each pricing zone.

Table 3.12: Reference Tariffs ($/GJ) proposed by NT Gas

Year Ending 30 June	2000	2001	2002	2003	2004
Zone 1	1.49	1.46	1.42	1.39	1.35
Zone 2	1.11	1.08	1.06	1.03	1.01
Zone 3	1.03	1.00	0.98	0.95	0.93

Source: Access Arrangement Information, p. 32.
Note: In dollars of the day.

Reference tariffs for each zone were determined by dividing the estimated throughput into the required revenue for that year. A smoothing parameter of X=-2.44 was applied to the Reference tariffs calculated for 2000 to provide a smooth price path for users over the access arrangement period, and to avoid price shocks at the commencement of the next access arrangement period. NT Gas used the following formula when applying the X factor to its tariffs:

$$t_n = t_{n-1}\,(1 + X)$$

NT Gas' access arrangement also provided for the calculation of reference tariffs if the revisions commencement date is later than 30 June 2004. The reference tariff would be adjusted on 1 July 2004 and then on each adjustment date thereafter using the following formula:

$$\text{Reference Tariff} = \text{Reference Tariff prior to Adjustment Date} \times \left[1 + \frac{\text{CPI}_{n} - \text{CPI}_{n-1}}{\text{CPI}_{n-1}}\right]$$

where 'adjustment date' means 1 January, 1 April, 1 July and 1 October.

Incentive mechanism

NT Gas proposed that the following mechanisms would provide an incentive for NT Gas to reduce total operating costs and increase pipeline throughput:[222]

- The rebate mechanism under the Interruptible Service permits some of the revenue from the rebatable service to be retained by NT Gas.

- The reference tariff for the reference service will apply during each year of the access arrangement period, regardless of whether the forecasts on which the reference tariff was determined are realised.

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[222] Access Arrangement, p.15.

Specifically, clause 9 of the reference tariff policy states:

> The rebate mechanism under the Rebatable Service is determined to provide NT Gas with an incentive to promote the efficient use of pipeline capacity and to provide other Users of the Pipeline with a share in gains from additional sales of Services.

Fixed principle

NT Gas proposed the following as a fixed principle:

> For the purposes of calculating the Capital Base at the commencement of the subsequent Access Arrangement Period, where the actual cost of New Facilities differs from the forecast New Facilities Investment on which the Capital Base was determined, the New Facilities Investment will be included at actual cost.[223]

3.9.3 Commission's *Draft Decision*

Based on its own calculations, the Commission proposed an alternative tariff path in the *Draft Decision* as set out in Table 3.13.

Table 3.13: Reference Tariffs (nominal $/GJ) calculated in *Draft Decision*

Year Ending 30 June	2002	2003	2004	2005	2006
Zone 1	0.82	0.82	0.81	0.81	0.81
Zone 2	0.57	0.57	0.57	0.57	0.56
Zone 3	0.51	0.51	0.50	0.50	0.50

The Commission proposed the following amendments to NT Gas' access arrangement:

Proposed Amendment A2.8

In order for NT Gas' access arrangement for the ABDP to be approved, NT Gas must amend the reference tariff proposed in Section 3 of the access arrangement. The amendment must have the effect that:

- the initial tariff (in 2001/02) is derived from the cost of service revenue resulting from the amendments proposed by the Commission in this *Draft Decision*; and
- in each subsequent year, the reference tariffs will be calculated using the CPI-X tariff escalator:

$$t_n = t_{n-1} (1 + (CPI_n - CPI_{n-1})/CPI_{n-1}).(1 - X)$$

where X = 2.47 per cent.

Section 3 of the access arrangement must be amended to remove the reference to CPI adjustment of NT Gas' proposed reference tariff for the year to 30 June 2004. In the event that there is a gap between the reference tariff years specified in the access

[223] Access Arrangement, p.16.

arrangement and the revisions commencement date, the interim reference tariff will be determined by adjusting the final year's reference tariff in accordance with the CPI-X methodology discussed in this amendment.

Proposed Amendment A2.9

In order for NT Gas' access arrangement for the ABDP to be approved, the access arrangement must be amended to include details of how revenue from interruptible services will be distributed.

Proposed Amendment A2.10

In order for NT Gas' access arrangement for the ABDP to be approved, the fixed principle (section 4.8) must be deleted.

3.9.4 Submissions from interested parties

Reference tariffs

In its submission, the Northern Territory (NT) Government argued that the Commission should set a reference tariff no lower than PWC's average cost of transportation.[224] The NT Government stated that PWC's cost of transportation is higher than the reference tariff determined by the Commission in its *Draft Decision*.

> The effect of imposing the reference tariff proposed in the ACCC's draft decision is to allow third party users, who have not taken any risk in the project, to have gas transported through the pipeline at a tariff substantially less than that which the instigator and foundation customer, the Territory Government/PWC, is obliged to pay… In addition, a tariff structure which sets the reference tariff below the foundation customer contract provides no incentive for similar long term agreements to be entered into by foundation customers and therefore has significant prospect of deterring, or at least delaying investment in required pipelines.[225]

The NT Government argued that the starting point for the Commission's assessment of the recovery of efficient costs, as given in section 8.1(a) of the Code, should be the price under the foundation contract.[226]

It was argued that a reference tariff lower than PWC's average cost of transportation would affect PWC's ability to compete in contestable electricity markets[227] and potentially strand PWC's generation assets.[228]

The NT Government also noted that, given the structure of PWC's haulage charge, a diminishing quantity of gas shipped by PWC on the pipeline will incur a corresponding increased haulage charge.[229]

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224 NT Government submission, 4 October 2001, p. 2.

225 NT Government submission, 4 October 2001, pp. 5–6.

226 NT Government submission, 4 October 2001, p. 5.

227 Zero contestability levels in the NT electricity market are expected to take effect from 2005, subject to a public benefit review to be carried out in 2002.

228 NT Government submission, 4 October 2001, p. 9.

Incentive mechanisms

NTPG endorsed the *Draft Decision's* findings on NT Gas' incentive mechanism. NTPG further stated:

> Equity demands that revenue benefits arising from sale of an interruptible service should be enjoyed by all stakeholders, and not captured solely by NT Gas. This is particularly the case in circumstances where offer of only the interruptible service condition is unwarranted and a consequence of improper use of monopoly power.[230]

Woodside proposed that average tariff revenue should be capped at CPI-X where X is an efficiency improvement factor of between 0.8 per cent and 1.5 per cent per annum over the access arrangement period.[231] Woodside stated:

> We believe that such a mechanism will promote efficiency and help lead to lower delivered prices for customers. We would encourage ACCC to consider whether a higher efficiency improvement factor would provide a greater incentive for the onshore gas transmission pipeline or distribution network operator to reduce costs and increases volumes.[232]

3.9.5 NT Gas' response to the *Draft Decision*

Tariff path

NT Gas stated it did not object to the proposed amendment, however, it did make the following comments:

- NT Gas assumed that the intent of the Commission's amendment was that the initial reference tariff be set in relation to the cost which are finally determined; and
- NT Gas did not accept that the formula specified in the amendment was any more accurate or appropriate than the formula more generally used in CPI based adjustments.

Incentive mechanisms

NT Gas stated that the proposed methodology for distribution of interruptible revenues recognises pre-existing obligations under the Amadeus Gas Trust, which requires NT Gas to deal with all pipeline revenue in a certain manner.

NT Gas believed it would be unable to identify how it would be able to accommodate the proposed amendment without describing the relevant provisions of the Trust, which is information confidential to the beneficiaries of the Trust.

Fixed principle

NT Gas had no objection to the removal of the fixed principle from the reference tariff policy.

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229 NT Government submission, 4 October 2001, p. 8–9.

230 NTPG submission, 2 August 2001, p. 5.

231 Woodside/Shell submission, 9 September 1999, p. 4.

232 Woodside Energy and Shell Development (Australia) submission, 9 September 1999, p. 4.

3.9.6 Commission's considerations

Reference tariffs and tariff path

Under the zonal tariffs proposed by NT Gas (Table 3.12 above), in the first year of the revised access arrangement period (that is, the year ending 30 June 2002) [233] a customer situated in Zone Three would pay the sum of the throughput charges for each zone, or \$3.46/GJ. Based on its own calculations, the Commission has determined reference tariffs as set out in Table 3.14.

Table 3.14: Reference Tariffs (nominal \$/GJ) calculated by the Commission

Year Ending 30 June	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Zone 1	1.26	1.26	1.27	1.28	1.29	1.30	0.97	0.97	0.98	0.99
Zone 2	0.89	0.89	0.90	0.90	0.91	0.92	0.68	0.69	0.69	0.70
Zone 3	0.74	0.74	0.75	0.75	0.76	0.76	0.57	0.57	0.57	0.58
	2.88	**2.90**	**2.92**	**2.94**	**2.96**	**2.98**	**2.22**	**2.23**	**2.24**	**2.26**

(Differences between zones and aggregate reference are due to rounding)

Under the Commission's proposed tariff path, for the year ending 30 June 2002, a customer in Zone Three would pay \$2.88/GJ. This represents a reduction of approximately 17 per cent when compared to NT Gas's proposal of \$3.46/GJ. The proposed tariffs calculated by the Commission have been escalated using a CPI-X mechanism where X = 1.51 per cent. This approach is discussed below.

CPI-X adjustment

As discussed earlier, NT Gas has proposed a price path using a tariff escalator of X = -2.44. While it is possible that the X factor used may already incorporate forecast changes in CPI, NT Gas' approach does not appear to explicitly provide for the effect on tariffs due to actual changes in the CPI.

Due to the absence of CPI in its formula, NT Gas' approach to smoothing tariffs over the access arrangement period results in NT Gas bearing the risk that inflation may be higher than expected. If this were the case, NT Gas would be under compensated for its actual costs. The Commission preference, as outlined in previous decisions, is to adopt a CPI-X tariff adjustment mechanism. This removes any inflation risk to the service provider, as tariffs are annually adjusted for actual changes in inflation. In calculating the tariff (t) for a particular year (year n) using a CPI-X adjustment, the Commission prefers the use of the following formula:

$$t_n = t_{n-1} (1 + (CPI_n - CPI_{n-1})/CPI_{n-1}).(1 - X)$$

233 As discussed in section 4.8 the access arrangement period will be until 1 July 2011, the Commission has therefore determined revenues for the ten-year period commencing 1 July 2001.

In its *Draft Decision*, the Commission proposed an amendment to the access arrangement to adopt the above CPI-X tariff adjustment mechanism. In response, NT Gas indicated that it had no objection to the amendment.

When NT Gas lodged its proposed access arrangement it was assumed that the access arrangement would commence on, or soon after, 1 July 1999 and that the revisions commencement date would be on, or soon after, 1 July 2004. Consistent with that expectation, NT Gas proposed reference tariffs for the years up to 30 June 2004 followed by CPI-X indexation thereafter until the revisions commencement date. This *Final Decision* provides for a revisions submission date of 1 January 2011 with a revisions commencement date six months after that date. It is proposed that the CPI-X indexation will similarly apply from the revisions submission date until the revisions commencement date.

NT Gas applied its X factor of -2.44 uniformly across all three zones. However, the Commission's preferred approach is to determine a different X factor for each zone. The volume forecasts provided by NT Gas show that throughputs for each zone do not increase uniformly over the access arrangement period. As throughput volumes are a key determinant of the level of tariffs, using the same X factor for each zone may not always adequately reflect the differences in throughput growth across zones.

For example, suppose throughputs for zone A of pipeline XYZ are expected to increase steadily over the next five years, but, throughput in zone B is expected to decrease substantially over the same period.[234] Smoothed individually, zone A would be subject to a positive X factor (that is, decreasing tariffs over time), whilst zone B would be subject to a negative X factor (that is, increasing tariffs over time). Moreover, applying the same X factor in both zones would effectively result in zone A subsidising zone B (that is, both tariffs would increase over time).

Consistent with this approach the Commission calculated an X factor for each zone. The X factor for Zones One, Two and Three were established as 1.52, 1.56 and 1.41 per cent respectively. The three X factors calculated are relatively close, which is most likely due to the pipeline being fully contracted with throughputs remaining fairly constant during the access arrangement period. Given the similarity in X factors across the three zones the Commission is of the view that the additional complexity associated with implementing individual X factors is unnecessary as this would have limited impact on the final tariffs calculated. It is the Commission's view that the potential detriment to users and potential users is negligible and that a single X factor is not contrary to section 2.24(f) of the Code. While the approach outlined above reflects the Commission's preferred approach to smoothing zonal tariffs, in this case the Commission considers that it is appropriate in the case of the ABDP that a single X factor of 1.51 per cent be applied when smoothing tariffs in each zone.

Once off tariff adjustment

As discussed in section 3.6.3, allowances for additional cost components have been included in the total forecast revenue calculation for the ABDP. However, payment of

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[234] As the majority of costs are allocated based on the proportion of ORC and pipeline length, the costs attributed to each zone will remain fairly constant over the ten year period.

one of the additional cost components ceases in June 2006 and therefore there is a subsequent drop of approximately $11m (on average) in forecast revenue for the following years until 2011. While the Commission would normally smooth tariffs over the duration of the access arrangement, in this instance the Commission considers that this approach could result in the inability of NT Gas to meet its costs as they fall due.

Sections 2.24 (a) and (b) of the Code require the regulator to take into account the service provider's legitimate interests and investment in the pipeline and the firm and binding contractual obligations of the service provider or other persons already using the pipeline. The Commission considers that smoothing tariffs over the duration of the access arrangement, rather than allowing for a step change in tariffs, could be contrary to the objectives set out in the Code. It is necessary to ensure that NT Gas receives a revenue stream sufficient to cover the efficient costs of service (section 8.1 (a)) and, in this instance, existing contractual obligations may affect NT Gas' ability to earn the revenue stream determined by the Commission. This issue is discussed in greater detail in a confidential Annexure E to this decision.

Therefore, the Commission has proposed that a once off tariff adjustment occurs in the 2006/2007 financial year, using the following formula.

$$t_n = t_{n-1}\,(1 + (CPI_n - CPI_{n-1})/CPI_{n-1}).(1 - X).Y$$

where Y = 0.74

where X = 1.51

The inclusion of a Y factor in the CPI-X formula allows for a step down in tariffs (and hence revenues) which correspond with the decrease in NT Gas' costs. A Y factor of 0.74 has been used by the Commission in its calculations, which results in a fall in tariffs of approximately 26 per cent in 2007/08. The adoption of the Y factor ensures a redistribution of NT Gas' revenues such that for each year of the access arrangement period, there is sufficient revenue to cover forecast costs. The Commission considers that this approach is consistent with ensuring that the objectives of sections 2.24 (a), (b) and 8.1(a) of the Code are met. It is also important to note that the NPV of future revenue streams are identical for both the unsmoothed and smoothed (with tariff adjustment) approaches.

Section 2.24 considerations

The Commission notes the concerns made by the NT Government and PWC who both sought to ensure that average reference tariff across the proposed zonal structure was above PWC's average haulage cost. If this was not the outcome, it was asserted by these parties that the interests of PWC may be adversely affected. It is the Commission's view that the average of its proposed zonal reference tariffs will not adversely impact on PWC or distort competition in markets that PWC competes. Such outcomes are consistent with the section 2.24(b), (e) and (f) of the Code.

The proposed tariff path, while it utilises a CPI-X (with the inclusion of a Y factor) framework, does not entail the inclusion of an efficiency mechanism. Rather it is a smoothing mechanism to redistribute revenues across the access arrangement period and this avoids a tariff shock at the commencement of the next access arrangement.

The forecast revenue is NPV neutral and does not deprive the service provider of any forecast revenue and is therefore not contrary to the service provider's legitimate interest under section 2.24(a) of the Code. The tariff smoothing is in the interests of users and prospective users section 2.24(f) of the Code by providing a mechanism to avoid tariff shocks for third parties at a later date.

Amendment FDA3.8

In order for NT Gas' access arrangement for the ABDP to be approved, NT Gas must amend the reference tariff proposed in Section 3 of the access arrangement. The amendment must have the effect that:

- the initial tariff (in 2001/02) is derived from the cost of service revenue resulting from the amendments proposed by the Commission in this *Final Decision*; and
- in each subsequent year, with the exception of the 2007/2008 financial year, the reference tariffs will be calculated using the CPI-X tariff escalator:

$$t_n = t_{n-1}\,(1 + (CPI_n - CPI_{n-1})/CPI_{n-1}).(1 - X)$$

where X = 1.51 per cent

- in the 2007/2008 financial year a once off tariff adjustment will occur and the tariff will be derived in accordance with the following formula:

$$t_n = t_{n-1}\,(1 + (CPI_n - CPI_{n-1})/CPI_{n-1}).(1 - X).Y$$

where Y = 0.74
X = 1.51 per cent

Section 3 of the access arrangement must be amended to remove the reference to CPI adjustment of NT Gas' proposed reference tariff for the year to 30 June 2004. In the event that there is a gap between the reference tariff years specified in the access arrangement and the revisions commencement date, the interim reference tariff will be determined by adjusting the final year's reference tariff in accordance with the CPI-X tariff escalator discussed in point two of this amendment.

Incentive mechanism

An incentive mechanism is an important component of an access arrangement and effective regulation. The Commission accepts that to the extent the reference tariff is able to encourage greater pipeline utilisation, the incentive mechanism proposed by NT Gas is consistent with the requirements of the Code.

In its access arrangement NT Gas states that revenue from interruptible services will be distributed in accordance with the requirements of the Amadeus Gas Trust (the Trust).[235]

[235] Access Arrangement, p. 6.

The Commission acknowledges that section 2.25 of the Code provides for the recognition of pre-existing contractual obligations and does not intend to interfere with existing contractual rights. However, in its *Draft Decision*, the Commission proposed an amendment to the access arrangement to include details of how revenue from interruptible services will be distributed. The Commission considered that while the rebate mechanism could not be modified, the proposed amendment would allow potential users to further understand their rights under the access arrangement.

In response, NT Gas submitted that it was unable to identify how it would be able to accommodate the proposed amendment without describing the relevant provisions of the Trust, which is information confidential to the beneficiaries of the Trust. The Commission accepts that this causes some difficulties with the implementation of its proposed amendment.

Since the release of the *Draft Decision*, NT Gas has provided the Commission with a copy of the Trust agreement, on a confidential basis. The Trust agreement sets out how any revenue earned on the pipeline are to be distributed. Therefore, this includes any revenue from the sale of interruptible services.

Clause 9 of NT Gas' reference tariff policy states that the rebate mechanism is determined to provide other users of the pipeline with a share in gains from additional sales of services.

The Commission is concerned that, given the pre-existing rights provided under the Trust, both existing and prospective users have no incentive to surrender capacity for interruptible use if they are not a beneficiary of the Trust. Given the structure of the Trust, the Commission considers it questionable whether users are able to 'share in gains from additional sales of services' as stated in NT Gas' access arrangement.

Therefore, while the Commission has decided not to pursue its original amendment, it does require NT Gas to amend its access arrangement to remove the above statement. The Commission considers that the statement may mislead users regarding the potential benefits arising from the rebate mechanism and the sale of interruptible services. Such an outcome would be contrary to the interests of users and prospective users under section 2.24(e) of the Code and would be an undesirable outcome.

Amendment FDA3.9

In order for NT Gas' access arrangement for the ABDP to be approved, the following statement must be deleted from Clause 9 of the reference tariff policy:

> 'and to provide other Users of the Pipeline with a share in gains from additional sales of Services.'

Fixed principle

NT Gas has proposed one fixed principle that requires new facilities investment be incorporated in the capital base at the commencement of the next access arrangement period at actual cost rather than forecast cost. The proposed fixed principle is duplicated in section 4.6 of the reference tariff policy and as such the Commission has previously analysed the provision in section 3.2.6 of this decision.

Previous decisions by state regulators have expressed considerable concern with proposed fixed principles that appear to unnecessarily limit the normal discretion provided to the regulator. These decisions have also argued that where a proposed fixed principle appears to reproduce the Code then the fixed principle is unnecessary and should not be accepted.[236]

Section 8.22 of the Code states that either the reference tariff policy should describe or the relevant regulator should determine whether (and how) the capital base at the commencement of the next access arrangement period should be adjusted if actual new facilities investment is different from forecast new facilities investment.

In this instance, section 4.6 of the reference tariff policy (after implementation of the Commission's Amendment FDA3.1) satisfies section 8.22 of the Code. Therefore, the fixed principle simply repeats a fundamental concept already established by the Code, the reference tariff policy and the Commission's own approach to regulation. In its *Draft Decision* the Commission considered that, the inclusion of the fixed principle was unnecessary and repetitious and proposed it be removed from the access arrangement. In its submission, NT Gas indicated that it has no objection to the amendment.

Amendment FDA3.10

In order for NT Gas' access arrangement for the ABDP to be approved, the fixed principle (section 4.8) must be deleted.

3.10 Assessment of reference tariffs and reference tariff policy

3.10.1 Code requirements

Section 3.5 of the Code requires the access arrangement to include a policy describing the principles that are to be used to determine a reference tariff (a reference tariff policy). This reference tariff policy must, in the regulator's opinion, comply with the reference tariff principles set out in section 8 of the Code.

The reference tariff policy and reference tariffs should be designed to achieve a number of objectives that are outlined in section 8.1 of the Code:

(a) providing the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the Reference Service over the expected life of the assets used in that Service;

(b) replicating the outcome of a competitive market;

(c) ensuring the safe and reliable operation of the Pipeline;

(d) not distorting investment decisions in Pipeline transportation systems or in upstream and downstream industries;

(e) efficiency in the level and structure of the Reference Tariff; and

[236] SAIPAR, Draft Decision: South Australian distribution system, April 2000; IPART, Final Decision: Albury Gas Company, December 1999; ORG, Final Decision: Victorian distribution, October 1998.

(f) providing an incentive to the Service Provider to reduce costs and to develop the market for Reference and other Services.

To the extent that any of these objectives conflict in their application to a particular Reference Tariff determination, the Relevant Regulator may determine the manner in which they can best be reconciled or which of them should prevail.

In addition, section 8.2 stipulates that when approving a reference tariff and reference tariff policy the regulator must be satisfied that:

(a) the revenue to be generated from the sales (or forecast sales) of all Services over the Access Arrangement Period (the Total Revenue) should be established consistently with the principles and according to one of the methodologies contained in this section 8;

(b) to the extent that the Covered Pipeline is used to provide a number of Services, that portion of Total Revenue that a Reference Tariff is designed to recover (which may be based upon forecasts) is calculated consistently with the principles contained in this section 8;

(c) a Reference Tariff (which may be based upon forecasts) is designed so that the portion of Total Revenue to be recovered from a Reference Service (referred to in paragraph (b)) is recovered from the Users of that Reference Service consistently with the principles contained in this section 8;

(d) Incentive Mechanisms are incorporated into the Reference Tariff Policy wherever the Relevant Regulator considers appropriate and such Incentive Mechanisms are consistent with the principles contained in this section 8; and

(e) any forecasts required in setting the Reference Tariff represent best estimates arrived at on a reasonable basis.

The reference tariff principles outlined in sections 8.1 and 8.2 are designed to provide flexibility so that reference tariffs and reference tariff policies can be designed to meet the specific needs of each pipeline.

However, section 8.1 includes objectives that may, at times, be in conflict with each other. On these occasions the regulator must determine how the conflict will be reconciled by reference to the factors in section 2.24 of the Code. Section 2.24 states:

... In assessing a proposed Access Arrangement, the Relevant Regulator must take the following into account:

(a) the Service Provider's legitimate business interests and investment in the Covered Pipeline;

(b) firm and binding contractual obligations of the Service Provider or other persons (or both) already using the Covered Pipeline;

(c) the operational and technical requirements necessary for the safe and reliable operation of the Covered Pipeline;

(d) the economically efficient operation of the Covered Pipeline;

(e) the public interest, including the public interest in having competition in markets (whether or not in Australia);

(f) the interests of Users and Prospective Users;

(g) any other matters that the Relevant Regulator considers are relevant.

The recent Western Australian Supreme Court Epic Energy's proposed access arrangement (the Epic Case) decision provides guidance as to the appropriate application of sections 8.1 and 2.24 by a regulator. The Court stated:

... The last paragraph of s8.1 recognises that the objectives of (a) to (f) in s8.1 may conflict in their application to a particular reference tariff determination, in which event the Regulator may

> determine the manner in which they can best be reconciled or which of them should prevail. Contrary to the submissions of the Regulator and Alinta, the discretionary task of seeking to reconcile conflicting objectives within s8.1, and even more significantly of determining which of them should prevail, cannot be decided by reference to s8.1 itself. Of necessity, the Regulator must have guidance outside of s8.1 in exercising those discretions. In this regard it appears from the structure and provisions of the Code that have been canvassed that s2.24(a) to (g) would most naturally guide the Regulator in the exercise of these discretions, and was intended to do so. That is, in exercising the discretions contemplated by the last paragraph of s8.1 the Regulator should take into account the factors in s2.24(a) to (g).[237]

3.10.2 NT Gas' proposal

Section 4 of the access arrangement is the reference tariff policy for the ABDP. This outlines the basis on which tariffs have been structured and states that NT Gas may undertake new facilities investment that does not meet the requirements of section 8.16 of the Code. The reference tariff policy also sets out incentive mechanisms for NT Gas and a fixed principle.

Section 3 of the access arrangement specifies the reference tariffs for the ABDP. This is supported by the reference tariff policy itself in addition to other material provided to the Commission by NT Gas.

3.10.3 Submissions from interested parties

Submissions to the Commission included significant comment on NT Gas' compliance with sections 8.1 and 8.2 of the Code. In particular, these comments focused on the initial capital base, depreciation and the level of the reference tariff. These concerns have been discussed in the relevant sections of this *Final Decision.*

3.10.4 Commission considerations

The Commission considers that NT Gas has complied with section 3.5 of the Code in providing a reference tariff policy in the access arrangement. A discussion on the reference tariff policy and the reference tariff methodology is located in this chapter of this *Final Decision*.

Each of the aspects of the reference tariff and reference tariff policy has been assessed in the relevant sections of this *Final Decision* together with a discussion of why the proposed amendments are necessary given the relevant provisions of the Code. The following discussion draws together the Commission's conclusions within the framework of sections 8.1 and 8.2 of the Code.

Pursuant to section 2.46 of the Code, when assessing proposed revisions to an access arrangement the Commission must take the factors set out in section 2.24 of the Code into account. The Commission has given due consideration to each of these factors in assessing NT Gas' proposed reference tariff and reference tariff policy (and the other elements set out in sections 3.1 to 3.20 of the Code) particularly where the objectives in section 8.1 conflict and the Commission, as the relevant regulator, must balance and

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237 Re Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231 at paragraph 85.

reconcile these objectives. In addition, where the Commission has exercised a discretion, it has been guided by the criteria in section 2.24.

The following discussion specifically comments on the application of these factors in respect of the reference tariff and reference tariff policy.

Section 8.1 criteria

Recovery of efficient costs associated with the provision of the reference service (8.1(a))

Section 8.1(a) provides that one objective which a reference tariff and a reference tariff policy should be designed to achieve is to provide the service provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the reference services over the expected life of the assets used in delivering that service.

In the Epic decision the Court noted that this objective does not necessarily set a ceiling or floor of the revenue that a service provider may earn. That is to say, the objective is not a revenue stream that recovers no more than efficient costs or at least efficient costs.[238] In assessing NT Gas' proposed rate of return (in the context of this chapter of the *Final Decision*) against this objective the Commission has particularly had regard to the factors (a) and (d) to (f) in section 2.24 of the Code. The Commission notes that in the Epic decision the Court took the view that 'legitimate' business interests are not limited to the recovery of normal profits or an economically efficient revenue stream.

It is important to note that the Commission does not consider this criterion guarantees a right for a service provider to recover monopoly profits. Criterion s2.24(a), to the extent that it allows such recovery, must be considered against other criteria contained in that section. While consideration must be given to each of these criteria, it ultimately falls to the Commission as the relevant regulator to decide how they should be balanced.

Subsequent to the *Draft Decision*, NT Gas advised the Commission that two cost factors were omitted as part of the derivation of the reference tariff. The Commission was previously unaware of these costs. It is the Commission's view that these additional cost factors should be included, one as part of the capital base, the other as a component of the cash-flow analysis. The background to, and assessment of these additional cost factors are contained within Annexures C and D due to their confidential nature. However, inclusion of these costs was a relevant consideration under section 2.24 of the Code.

In this *Final Decision* the Commission has also assessed the future capital expenditure and non-capital costs proposed by NT Gas. On the basis of available information and a number of key performance indicators, the Commission considers the forecast capital expenditure and non-capital costs proposed by NT Gas to not be unreasonable. Forecast capital expenditure will also be assessed again at the end of the access arrangement period under section 8.16 of the Code. The Commission has also accepted the forecast expenditures for the two additional cost components.

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[238] ibid., at paragraph 142.

NT Gas has proposed a cost of service approach under which the total revenue requirement equates to the cost of providing the reference service. Under this approach the regulator is obliged to approve reference tariffs which deliver a revenue stream sufficient to recover the efficient costs of providing reference services. The 'efficient costs' test refers to both non-capital costs (such as operating and maintenance costs) and capital expenditure. Only those costs incurred by a prudent service provider acting efficiently should be included.

The Commission considers that the revenue stream proposed by NT Gas would provide a return that is in excess of the recovery of efficient costs associated with the reference service. In the Commission's view, the WACC and associated parameters, the initial capital base and the depreciation schedule proposed by NT Gas are not consistent with the principle of recovering efficient costs.

Given the circumstances of the ABDP, it is unlikely that reference services will be sold in this access arrangement period. However, the reference tariff resulting from the parameters proposed in the *Final Decision* would provide the service provider with the opportunity, if it were supplying the reference service, to earn a stream of revenue that would recover the efficient costs associated with that service.

The Commission considers that the amendments it requires to be made to the reference tariff policy will generate a revenue stream that is comparable with the efficient costs of providing the reference service and is consistent with the objective in section 8.1(a) and the factors in section 2.24.

Replicating the outcome of a competitive market (8.1(b))

Setting the regulated rate of return of CAPM benchmarks results in a return that is expected to be similar to those achieved by firms facing similar commercial risks operating in a competitive environment. The return should be based on only those assets necessary to deliver the services required, consistent with section 2.24(d). The reference tariffs also allow NT Gas to achieve a return in excess of a normal return from increased efficiencies and growth in sales, as occurs in a competitive market.

Pricing that is reflective of efficient costs is also a feature of competitive markets and, as noted in reference to section 8.1(a) above, the Commission aims to ensure that tariffs are reflective of efficient costs to the extent that this is practicable and reasonable.

Ensuring the safe and reliable operation of the pipeline (8.1(c))

The reference tariffs are based on cost forecasts as being necessary for the safe and reliable operation of the pipeline and are also consistent with the safety and technical requirements of section 2.24(c) of the Code.

Not distorting investment decisions in pipeline transmission or in upstream or downstream industries (8.1(d))

The Commission has also included in the ICB an additional capital cost component it was previously unaware of at the time the *Draft Decision* was released. The inclusion of this cost factor in the ICB has been guided by the Commission's consideration of section 2.24 factors. The reasons for its inclusion in the ICB are discussed in chapter two while Confidential Annexure C addresses those issues that are confidential in nature.

Efficient investment decisions in upstream and downstream markets will be facilitated by transmission prices based on an allocation of costs to users which approximates long run costs of providing the service. This is approximated by the adoption of tariffs which are consistent with sections 8.38 to 8.43 of the Code. Efficient investment decisions for pipeline systems are also likely to follow if an appropriate rate of return is applied to the asset. The return should be neither excessively high so as to encourage over investment, nor so low as to discourage efficient investment in the pipeline. Conversely, excessive returns may discourage efficient investment in upstream and downstream markets while inadequate returns may encourage over investment in the short term (possibly leading to lower investment levels in the long term).

The rate of return set by the regulator should be sufficient to cover the service provider's cost of capital. A rate of return that is lower than that required by investors will be insufficient to attract investment in the long run. On the other hand, a higher than required rate of return will enable the service provider to set higher tariffs, earn monopoly rents and will result in a misallocation of resources. The Commission considers that the rate of return determined in this *Final Decision* will not distort investment decisions.

Inter-temporal investment distortions are minimised by the smoothed price path provided by the Commission's proposed CPI-X tariff adjustment mechanism, which produces relatively stable prices over the access arrangement period. The shift from 'postage stamp' pricing to zonal tariffs also represents an improvement in the locational pricing signals sent to downstream investors.

In its access arrangement information, NT Gas stated that the revenue earned under existing transportation contracts is less that the total revenue NT Gas would be entitled to recover under the Code. In the Commission's view the ICB and rate of return used by NT Gas overstated the initial capital base, depreciation schedule and return on capital. If the ICB and rate of return methodologies are correctly applied in accordance with the principles outlined in this *Final Decision*, the result is a lower reference tariff that, in the Commission's view, still meets the revenue requirement of an efficient pipeline operator.

These outcomes suggest that the amendments the Commission has proposed to NT Gas' reference tariff policy and reference tariff are consistent with the objective of not distorting investment decisions for the reasons outlined above.

Efficiency in the level and structure of the reference tariff(s) (8.1(e))

The zonal tariff structure proposed by NT Gas creates three postage stamp tariffs in the place of the existing 'postage stamp' tariff, with gas transportation charges varying between each zone. The Commission is of the view that distance based tariffs are likely to provide better price signals to the market than 'postage stamp' or zonal tariffs. However, given that most customers are located at the end of the ABDP the Commission considers that any loss in efficiency due to a zonal tariff would be minimal.

The Commission's *Final Decision* rejects NT Gas' proposed tariff and the use of a smoothing parameter of X= -2.44. When determining the tariff path for the access arrangement period, the Commission prefers the use of a CPI-X approach. This approach, unlike NT Gas', explicitly provides for the effect on tariffs due to actual changes in the CPI and removes the inflation risk inherent in NT Gas' approach.

Incentives to reduce costs and expand the market (8.1(f))

NT Gas has sufficient incentive to reduce costs and expand the market, as any benefits arising from reduced costs and/or higher than forecast volumes can be retained by NT Gas during the term of the access arrangement period.

In its access arrangement NT Gas stated that its rebatable service is designed to provide NT Gas with an incentive to promote the efficient use of pipeline capacity and to share gains with users from additional sales of services. The Commission has considered the proposed incentive mechanism and has determined that there are unlikely to be benefits to third parties, other than those who are party to the Amadeus Gas Trust. Accordingly, the Commission has decided that the incentive mechanism should be modified to delete the reference to sharing gains from the sale of additional pipeline services with users.

Despite the modification of the proposed incentive mechanism, the service providers still has an incentive to reduce costs and expand the market during the period of the access arrangement.

Section 8.2 Factors

Section 8.2 of the Code lists five factors about which the Commission is to be satisfied in determining whether to approve the reference tariff. These are assessed below.

Total revenue is established consistently with the principles and according to one of the methodologies contained in section 8 of the Code (8.2(a))

NT Gas has determined its revenue requirement based on a cost of service approach with a smooth price path to avoid price shocks. This approach is consistent with the Code.

However, while NT Gas has utilised the cost of service approach in determining its reference tariff, it is the Commission's view that NT Gas' proposed capital base, rate of return and depreciation allowances are overstated. As a result of the amendments proposed in this *Final Decision,* NT Gas' revenue stream is less that that proposed by NT Gas.

The proportion of total revenue that any one reference tariff is designed to recover is calculated consistent with the principles of section 8 of the Code (8.2(b))

Sections 8.38 to 8.41 of the Code provide guidance favouring cost-reflective pricing, to the maximum extent that is commercially and technically reasonable. These provisions are subject to considerations of providing incentives for market growth and avoiding loss of supply opportunities.

NT Gas' access arrangement includes a single reference service (transportation service). Accordingly, for tariff setting purposes NT Gas has allocated all costs to this service and assumed all volumes relate to this service. While this approach may at first seem inconsistent with the Code, little revenue is expected from other services and a more precise methodology of allocating total revenue is not considered necessary at this point in time.

The proportion of total revenue recovered from users of a service is calculated consistent with the principles of section 8 of the Code (8.2(c))

NT Gas has determined only one reference tariff (comprising of three zonal tariffs) for its reference service. The Commission has assessed the information used by NT Gas to determine and allocate costs for each zone and is satisfied with the methodology used.

The Commission considers that, after implementation of the proposed amendments, the tariffs would recover from each user a fair and reasonable share of costs, outlined in this *Final Decision*.

Incentive mechanisms that are incorporated are consistent with the principles of section 8 of the Code (8.2(d))

In addition to the ability to retain additional revenue from an increase in volumes, NT Gas' proposed an incentive mechanism that permits some of the revenue from the rebatable service to be retained by NT Gas. The Commission accepts that to the extent the reference tariff is able to encourage greater pipeline utilisation, the incentive mechanism proposed by NT Gas is generally consistent with the requirements of the Code. However, as noted above, the Commission has proposed an amendment to the access arrangement that reflects the impact of the Amadeus Gas Trust on the effectiveness of the proposed incentive sharing mechanism, particularly as the potential benefits from such a scheme are only accessible to parties to the Trust.

Forecasts used are best estimates determined on a reasonable basis (8.2(e))

The Commission considers the forecast costs are not unreasonable. The forecast volumes provided by NT Gas are essentially equivalent to the existing capacity of the pipeline and are therefore considered acceptable.

4. Non-tariff elements

In this chapter the mandatory non-tariff elements of the proposed access arrangement for the ABDP are assessed for compliance with the Code. Issues are presented in the following format:

- Code requirements for each mandatory element
- NT Gas' proposal
- Commission's *Draft Decision*
- Issues raised in submissions
- NT Gas' (and others' where applicable) response to the *Draft Decision*
- Commission's considerations
- Where relevant, this is followed by amendments that the Commission requires for the access arrangement to be approved. All amendments are replicated in the executive summary.

4.1 Code Requirements

Section 3 of the Code establishes the minimum content of an access arrangement, which includes the following non-tariff mandatory elements:

- a services policy that must contain at least one service that is likely to be sought by a significant part of the market;
- terms and conditions on which the service provider will supply each reference service;
- a capacity management policy to state whether the covered pipeline is a contract carriage or market carriage pipeline;
- in the case of a contract carriage pipeline, a trading policy which refers to the trading of capacity;
- a queuing policy which defines the priority that users and prospective users have to negotiate capacity where there is insufficient capacity on the pipeline;
- an extensions/expansions policy which determines whether an extension or expansion of a covered pipeline is or is not to be treated as part of the covered pipeline for the purposes of the Code; and
- a review date by which revisions to the access arrangement must be submitted and a date on which the revisions are intended to commence.

- An access arrangement must also contain a reference tariff policy and at least one reference tariff. These provisions were assessed for compliance with the Code in chapter 3.

4.2 Services Policy

4.2.1 Code requirements

Sections 3.1 and 3.2 of the Code require an access arrangement to include a services policy which must include a description of one or more services that the service provider will make available to users and prospective users. The policy must describe any services likely to be sought by a significant part of the market, and that in the relevant regulator's opinion should be included in the services policy.

When practicable and reasonable, a service provider should make available those elements of a service required by users and prospective users and, if requested, apply a separate tariff to each element.

4.2.2 NT Gas' Proposal

NT Gas' proposed services policy consisted of three services – a Transportation Service, an Interruptible Service and a Negotiated Service.

NT Gas has described the three services in the following manner:

> **Transportation Service** — Reference Service for transport from the Receipt Points to any Delivery Points on the Pipeline with tariffs charged on the basis of throughput ($ per GJ of throughput).
>
> **Interruptible Service** – Rebatable Service (non-Reference Service) for transport from the Receipt Points to any Delivery Points on the Pipeline with tariffs charged on the basis of throughput ($ per GJ of throughput), where NT Gas is entitled to cease receiving gas from, or delivering gas to, the User when pipeline capacity is constrained/curtailed or to meet the capacity requirements of other Users.
>
> **Negotiated Services** — agreements negotiated to meet the needs of a User which differ from those in the Transportation Service or the Interruptible Service.

NT Gas' proposal was outlined in more detail in section 3.2.2 of the Commission's *Draft Decision*.

4.2.3 Relevance of existing haulage agreements to range of services offered to third parties.

The main existing haulage agreement is between NT Gas and PWC, and is due to expire in 2011. According to NT Gas, there is currently no firm capacity available in the pipeline.[239]

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[239] NT Gas Access Arrangement, 25 June 1999, Section 1, page 3.

Due to a number of features of the current haulage arrangements, transportation services are unavailable to third parties unless the pipeline system is expanded, extended, or the party negotiates with existing users for access to their reserved capacity.

In relation to the potential for interruptible service, there is in the vicinity of 5TJ/d of capacity available on an interruptible basis. The availability of such capacity depends on seasonal factors reflecting the fact that gas is transported through the ABDP is primarily used for power generation. PWC has indicated that there is likely to be some interruptible capacity available. However, PWC has noted that it is unlikely that the capacity will be available when required by any other generator of electricity.[240]

In addition to the users' rights to use the pipeline's total capacity, the current users with existing contractual rights in force as at 25 June 1999 have the right to increase capacity reservation over any request from a user that has not yet entered into a service agreement.[241]

Section 4.6.4 of the *Final Decision* discusses the impact that the existing users pre-emptive rights to capacity have on the queuing policy.

Code provisions

The main objective of the Code is to ensure that users and prospective users are able to gain access, on reasonable terms, to services utilising spare capacity in the pipeline system. The notion of spare capacity includes not only uncontracted capacity but also contracted but unused capacity.[242]

The notion of access to reserved but unused capacity does not confer any power on the regulator or arbitrator to interfere with the rights of existing users under contracts already in place. However, there is an exception to the requirement to give effect to existing firm and binding contractual obligations. Sections 2.25, 2.47 and 6.18 of the Code all state that the regulator or the arbitrator must not make a decision that has the effect of depriving a person of an existing contractual right, 'other than an Exclusivity Right which arose on or after 30 March 1995'.

4.2.4 Commission's Draft Decision

The Commission's *Draft Decision* accepted that there was limited capacity available for third party access as a consequence of existing haulage agreements.

The Commission gave consideration to requiring NT Gas to incorporate in the access arrangement, pursuant to section 3.17(ii) of the Code, a trigger for early review in the event that a 'significant event' occurs. This would give other interested parties the opportunity to make submissions for changes to the access arrangement, in the case that a trigger was activated.

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240 PWC submission, 17 November 1999, p.3.

241 NT Gas Access Arrangement, 25 June 1999, Section 6.4, p. 19.

242 (See in particular the definition of 'Spare Capacity' in section 10.8 of the Code, and sections 3.2, 3.6, 3.12, 5.4, 5.9 and 6 and the overview of section 6 of the Code.)

The *Draft Decision* proposed the following amendment:

Proposed Amendment A4.1

For the access arrangement to be approved, the Commission requires that NT Gas amend the access arrangement by defining, in response to the further process of public consultation, specific major events (if any) that would trigger an obligation on the service provider to submit revisions prior to the revisions submission date.

4.2.5 Submissions by interested parties

Two issues were raised in respect of NT Gas' proposed services policy:

- ABDP system capacity constraint; and
- the lack of provision in the access arrangement for a back haul tariff.

System capacity constraint

NTPG disputed the claim by NT Gas that capacity limitations are a constraint on sale of the reference service or negotiated service within the access arrangement. NTPG submitted, 'that provided an adequately sized second compressor is funded by PWC under existing lease obligations, ABDP system capacity constraints will not prevent sale of the Reference Service over the access arrangement period'.[243]

PWC responded to NTPG's comments in relation to PWC's obligation to fund a second compressor pursuant to its agreement with NT Gas. PWC rejected the notion that it had an immediate obligation to fund an additional compressor.[244] NT Gas stated:

> Where a party (including PWC) has capacity requirements, which require an additional compressor, that party will be responsible for funding the installation of the compressor. In respect of any obligation, which may exist under the Gas Sales Agreement for PWC to fund another compressor, this is a confidential contractual matter between NT Gas and PWC and is not an appropriate matter for third parties to seek to enforce through the access arrangement.[245]

In a subsequent submission, NTPG argued that NT Gas should be required to provide an uninterruptible service to NTPG on the basis that it believes PWC has not fully used its nomination for uninterrubtible service, and the fact that NTPG's interruptible service has not yet been interrupted.[246]

Back haul reference service

Santos and Woodside both commented on the lack of provision for back haul in the access arrangement. Santos argued that an offshore NT Gas development such as the Petrel-Tern Project would require a back haul service. Santos and Nabalco noted that the proposed access arrangement does not account for the potential gas transportation

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243 NTPG submission, 12 September 1999, p. 6.

244 PWC submission, 17 November 1999, p. 3.

245 Email from Agility Management, on behalf of NT Gas, to Commission staff, 27 March 2001.

246 NTPG submission, 2 August 2001, p.1-2.

issue associated with an offshore NT Gas development such as the Petrel-Tern Project. Santos is concerned that the Petrel-Tern project would require them to negotiate back haul tariffs. If a commercial tariff could not be agreed upon, this could potentially cause the project to remain undeveloped.[247]

Santos considered that it would potentially require access to the ABDP for back haul services sometime between 2002 and 2005, within this access arrangement period.[248] Woodside stated that it is planning together with Shell the development of its Timor Sea gas resources. This project requires the provision of a back haul service on the ABDP.[249] Nabalco raised the possibility that gas brought onshore from Timor Sea could be available in Darwin as early as late 2003.[250]

NTPG stated in its submission of 2 August 2001 that it does not support the consideration of back haul tariffs at this time. NTPG stated that:

> Speculation regarding LNG export facilities being constructed at Darwin for Timor Sea gas reserves has surfaced frequently in the last twenty years. Firm project commitments which would result in this gas invading the Darwin markets seem no more concrete at present than on previous occasions.
>
> Considering the uncertainties involved in such a future scenario, and the effort required of the Commission in determining an appropriate back haul tariff regime, the exercise is not warranted at this time.[251]

NTPG did state however that it was in favour of the inclusion of a trigger mechanism to address future back haul requirements.[252] Santos also stated that it was in favour of a section 3.17 trigger mechanism to address back haul services, but expressed that such a review should not be limited in scope at this time.[253]

Conversely, PWC submitted that it is opposed to the inclusion of a trigger mechanism. PWC believe that should Timor Sea gas come on shore to Darwin, it would either be transported by:

- a new large diameter pipeline such as that proposed by Epic Energy, leaving the ADBP largely stranded after 2011; or

- a new pipeline system incorporating the ADBP, in which case the ADBP would become subject to a new access arrangement as part of the new pipeline system.[254]

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[247] Santos submission, 8 September 1999, p.4.

[248] Santos submission, 8 September 1999, p. 3.

[249] Woodside submission, 9 September 1999, p. 1.

[250] Nabalco submission, 9 September 1999, p. 2.

[251] NTPG submission, 2 August 2001, p.6.

[252] NTPG submission, 2 August 2001, p.6.

[253] Santos submission, 8 June 2001, p.3-4.

[254] PWC submission, 4 October 2001, p.6.

4.2.6 NT Gas' Response to Draft Decision

Capacity constraint

The Commission requested that NT Gas respond to NTPG's arguments with respect to the availability of firm capacity. In an email[255] to the Commission, NT Gas explained that due to its existing haulage agreements, a prudent operator would not enter into a commitment to provide capacity every day of the contract term where there is not reasonable confidence of being able to meet that obligation.

Review trigger

In its submission of 14 November 2001, NT Gas presented its opposition to the inclusion of a review trigger.

> As a general matter, NT Gas does not support the inclusion of trigger events where access arrangements which are established for only five years. As the NSW Independent Pricing and Regulatory Tribunal has noted[256] "for incentive regulation to be effective, the general regulatory consensus is that a review period should normally be four-five years".
>
> The effect of a trigger event is generally a full review of the access arrangement notwithstanding that the trigger is designed to address one specific issue. It would be an undesirable outcome in terms of increased regulatory cost, uncertainty, and the reduced effect of incentive mechanisms, if triggers unnecessarily lead to a premature review of an access arrangement.

Following discussions between NT Gas and the Commission in 2002 however, NT Gas has indicated that would not be opposed to a trigger mechanism if the access arrangement period was ten years rather than five.[257] The Commission has decided to accept NT Gas' request for an access arrangement period till the end of the foundation contracts in 2011, and has required a section 3.17(ii) trigger to be included in the access arrangement. The access arrangement period and trigger mechanism are discussed in section 4.8.6.

4.2.7 Commission's Considerations

The Commission's *Final Decision* was influenced by the existing haulage agreements to which NT Gas is a party. NT Gas has argued that given its existing capacity is fully committed it has limited scope to offer the reference service during the first access arrangement without enhancement of the pipeline system.

While NTPG claimed that PWC has an immediate obligation to fund a second compressor pursuant to its agreement with NT Gas, this is not appropriate for this *Final Decision,* as it is a contractual matter between NT Gas and PWC.

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[255] Email from NT Gas to Commission staff, 22 January 2002

[256] IPART, Final Decision on AGLGN Access Arrangement for NSW Distribution Network, page 329.

[257] Email from NT Gas to Commission staff, 5 June 2002.

Reference Transportation Service

The Commission considers that the transportation service proposed by NT Gas meets the requirements of users and potential users in terms of section 3.2 of the Code.

In reaching this decision, the Commission has been guided by the Code, which requires the Commission to have regard to the constraints arising from the existing haulage contracts other than exclusivity rights arising on or after March 1995. This approval of the proposed reference service is qualified by the modifications of the reference tariff provisions, access policies and terms and conditions of service required by the Commission in amendments proposed elsewhere in the *Final Decision*.

Rebatable Interruptible Service

The Commission accepts that the revenues likely to be derived from interruptible service are unpredictable and that it is appropriate for the interruptible service to be a rebatable service. The Commission acknowledges that provisions of the existing haulage agreements prevent NT Gas from specifying in its access arrangement the exact quantity of gas that will be available for the interruptible service.

Negotiated Service

A negotiated service is a common element in recent access arrangements and proposed access arrangements. They enable service providers to accommodate any special requirements of a user or a potential user, such as a back haul service.

Access and Requests for Services

The Commission considers that NT Gas' proposal provides reasonable time to complete a request for service. As there is insufficient capacity to satisfy a request for a prospective user, the Commission believes the queuing policy and extensions and expansions policy are a significant factor for the prospective user in gaining access to capacity.

Requests for a back haul reference service

The Commission could require the inclusion of a tariff for back haul services if the Commission is of the view that section 3.3 of the Code is satisfied.

Section 3.2 of the Code specifies the principles according to which services must be described in the access arrangement. Section 3.2(a)(ii) allows the Commission to require the service provider to include a service description for any service that it considers 'should be included in the Services Policy', whether or not it is likely to be sought by a significant part of the market.

Section 2.24 of the Code provides, that:

> The Relevant Regulator may approve a proposed Access Arrangement only if it is satisfied that the proposed Access Arrangement contains the elements and satisfies the principles set out in section 3.1 to 3.20. The Relevant Regulator must not refuse to approve an Access Arrangement solely for the reason that the proposed Access Arrangement does not address a matter that sections 3.1 to 3.20 do not require an Access Arrangement to address.

In the light of section 2.24, the intention of section 3.3 is that, while the service provider must include a tariff for at least one service that is likely to be sought by a significant part of the market, and may include a tariff for more than one service, the Code does not require it to include a Reference Tariff for a service that is not 'likely to be sought by a significant part of the market'.

Does a back haul service satisfy the test in section 3.3?

In analysing whether or not a service is 'likely to be sought by a significant part of the market', it is worth testing the notion of 'likely' and 'significant' in regard to the particular service.

Likely

The notion of 'likely' means at its lowest that there is a 'real chance or possibility' that something will occur,[258] and at its highest that is 'more probable than not' that an event will occur.[259]

When looking at the notion of 'likely' there are two main issues that must be tested:

- the likelihood of any parties seeking a back haul tariff in the event that Timor Sea gas comes onshore to Darwin; and
- the likelihood that Timor Sea gas will come onshore to Darwin.

In regard to any parties seeking a back haul tariff, the Commission notes that three independent entities, Woodside, Santos and Nabalco have made submissions indicating an intention to seek a back haul tariff. These submissions are strong evidence of a likelihood that at least one of these entities will seek the service in the event that Timor Sea gas comes onshore to Darwin.

In regard to gas coming onshore from the Timor Sea, the Commission notes that a number of plans for developing gas reserves have been articulated, however, at this stage it is inconclusive whether or not these plans will reach fruition. See section 3.2.6 of the Commission's *Draft Decision* for a discussion of various development plans.

Significant

The notion of 'significant' is less onerous than 'substantial', and may mean no more than that the part of the market seeking the service must not be 'insignificant'.

The Commission considers that the parties that would request a back haul service in the event of gas coming onshore from the Timor Sea, make up a 'significant' part of the market. The three parties include:

- Woodside, a major participant in the Northern Australia Gas Venture (Greater Sunrise and Evans Shoal Gas fields) and the Laminaria/Corallina project;

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[258] See Deane J in *Tillmanns Butcheries Pty Ltd v The Australian Meat Industries Employees Union* (1979) ATPR 40-138 at p. 18,5000.

[259] See Bowen CJ in the *Tillmanns Butcheries case.*

- Santos, an operator of the Petrel and Tern offshore gas fields; and
- Nabalco, manages the Gove Joint Venture bauxite mine and alumina refinery situated in Arnhem land.

If gas is brought onshore to Darwin, it will represent an alternative gas source to the Amadeus Basin. An indication of the demand for back haul services is reflected by the average daily and peak demands of gas for customers along the ABDP, other then Darwin customers. The access arrangement information provides a table of the load profiles in 1998.[260] It appears that 5154.6 TJ/Annual (which is 32 percent of the total annual volume) of the ABDP gas was demanded from customers other than Darwin customers.

Conclusion

The Commission considers that in the event that Timor Sea gas is brought onshore to Darwin, a 'significant' part of the market would be likely to demand a back haul service. Based upon available information that was received as part of the *Draft* and *Final Decision* consultation process, the Commission considers that the comments by interested parties and the uncertainty surrounding Timor Sea developments that it is not necessary to include a back haul reference service in the initial access arrangement period.[261] However, in recognition of the possibility that Timor Sea gas may be brought onshore before 2011, the Commission has decided to include a trigger mechanism for an early review of the access arrangement, under section 3.17(ii) of the Code.[262] As part of a triggered review, the Commission could require NT Gas to include a service description and tariffs for a back haul service if it became clear that it was sought by a significant part of the market.

It is the Commission's view that the inclusion of the trigger mechanism can address the interests of users, and potential users such as Santos, Woodside and Nabalco in the context of gas developments off Australia' northern coast. This can be achieved in accordance with section 2.24(f) of the Code by providing the opportunity for the provision of a backhaul service. The possibilities created by the inclusion of a trigger mechanism would also be compatible with facilitating competition in related markets and would be consistent with section 2.24(e) of the Code. The inclusion of a trigger mechanism addresses the specific request by Santos and NTPG.

The Commission is also of the view that the inclusion of the review trigger mechanism is in the public interest under section 2.24(e) and has the potential to promote competition in related markets through a review of the access arrangement by requiring the provision of a service likely to be sought by a significant part of the market.

The Commission has considered PWC's comments that indicated that a trigger mechanism should not be included as gas from new projects would be transported

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[260] NT Gas Access Arrangement Information, 25 June 1999, Section 5.3, p. 39 – 40.

[261] It should also be noted that the inclusion of the negotiated service provides for back haul services prior to a triggered review. Should a user be unsuccessful in negotiating the terms and conditions of such a service (including tariffs), that user could notify a dispute under section 6 of the Code.

[262] See section 4.8.6 of the Final Decision for further discussion.

through a system other than the ABDP. It is the Commission's view that as such an outcome can not be known with certainty the protection of the interests of users, prospective users and broader public interest under sections 2.24(f) and (e) of the Code would be served by the inclusion of a trigger mechanism.

Under the regulatory framework, users can request a negotiated service, it is the Commission's view that this also provides an opportunity for a user to seek access to backhaul services, particularly if conditions preclude the operation of the trigger mechanism. Therefore the Commission considers this possibility under the Code as a relevant consideration and a potential outcome in the interests of users under section 2.24(f).

The Commission has decided not to require the inclusion of a backhaul service in this initial access arrangement.

4.3 Terms and Conditions

4.3.1 Code requirements

Section 3.6 of the Code requires an access arrangement to include the terms and conditions on which a service provider will supply each reference service. These terms and conditions must be reasonable according to the relevant regulator's assessment.

4.3.2 NT Gas' proposal

NT Gas stated that it will provide the reference service on the terms and conditions set out in its standard service agreement for the reference service. The key terms and conditions are set out in Schedule 2 of the access arrangement.

Schedule 2 is divided into three parts:

1. general – topics include: relationship between NT Gas and user; obligation to transport; gas pressure; nominations; MHQ, MDQ and ACQ; daily variance; system use gas linepack; metering; allocation; accounts and payments; force majeure; liabilities and indemnities; interruptions and curtailments; option to extend; title to and responsibility for gas; metering and records; gas quality; part periods; and overruns;

2. calculation of imbalance; and

3. connection of metering facilities to the pipeline.

NT Gas stated that it will not discriminate between prospective users in the provision of services on the basis of:

(a) past transactions or relationships with NT Gas;

(b) the identity of the prospective user;

(c) the fact that the prospective user is a related part of NT Gas; or

(d) the source of the gas proposed to be transported, subject only to the gas meeting the specifications.

More detailed discussion of the terms and conditions can be found in section 3.3.2 of the Commission's *Draft Decision*.

4.3.3 Commission's Draft Decision

The Commission's *Draft Decision* required the following amendments with respect to terms and conditions:

Proposed Amendment 4.2

In order for NT Gas' access arrangement for the Amadeus Basin to Darwin Pipeline to be approved, NT Gas must amend the access arrangement to state that NT Gas will seek to amend its access arrangement following any recommendations by the AGA Gas Quality Specifications Working Group to adopta more flexible gas specification.

Proposed Amendment 4.3

In order for NT Gas' access arrangement for the Amadeus Basin to Darwin Pipeline to be approved, NT Gas must clearly specify that Schedule 2 of the access arrangement prevails over the standard service agreement.

Proposed Amendment 4.4

In order for NT Gas' access arrangement for the Amadeus Basin to Darwin Pipeline to be approved, NT Gas must include in the access arrangement the prudential requirements relevant for users and prospective users.

4.3.4 Submissions by interested parties

Prior to the Commission's *Draft Decision*, Santos submitted that existing and potential gas users and gas suppliers should be consulted regarding the appropriate gas specification for the ABDP system. Santos stated that such an approach is preferable to the imposition of a standard, which may result in additional upstream costs to meet a rigid specification, which is not necessary for the Northern Territory's dominant industrial user base.[263] There were no other submissions by interested parties concerning the terms and conditions of NT Gas' proposed access arrangement.

4.3.5 NT Gas' Response to Draft Decision

NT Gas responded favourably to the Commission's proposed amendments, with some suggested improvements with respect to gas specification.

Gas Specification:

> NT Gas would not object to providing for adoption of a revised gas specification subject to:

[263] Santos submission, 8 September 1999, p. 5.

- the enactment of any legislation necessary to facilitate the change in specification;
- recognition and preservation of existing contractual rights and obligations; and
- the specification not precluding continued transportation of gas from existing fields.

> NT Gas believes that it is unnecessary and undesirable to require formal revisions to the access arrangement to implement an amended specification due to the cost and time involved in revising the access arrangement. Instead, the intended outcome would be better implemented through the access arrangement providing for substitution of the revised specification in place of the specification detailed in the access arrangement.
>
> NT Gas notes that this approach has been accepted by the Commission and other regulators – for example, access arrangements for Central West Pipeline and the AGL Gas Networks Limited NSW distribution network.[264]

Priority of schedule 2:

> … NT Gas would not disagree with an amendment which required the access arrangement to specify that … in the case of inconsistency between the documents the terms and conditions described in the access arrangement will prevail over the terms of the standard transportation agreement.[265]

Prudential requirements:

> NT Gas proposes that the prudential requirements applicable to users and prospective users to be described in the access arrangement are as follows:

- The user or prospective user must be resident in, or have a permanent establishment in, Australia;
- The user or prospective user must not be under external administration as defined in the Corporations Law or under any similar form of administration in any other jurisdiction;
- The user or prospective user may be required to provide reasonable security in the form of a parent company guarantee or a bank guarantee or similar security. The nature and extent of the security will be determined having regard to the nature and extent of the obligations of the user or prospective user under the Service Agreement.[266]

4.3.6 Commission's Considerations

Subject to the amendments presented below, the Commission considers that the terms and conditions proposed by NT Gas are reasonable and meet the requirements of section 3.6 of the Code.

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264 NT Gas submission, 14 November 2001, p.26.

265 NT Gas submission, 14 November 2001, p.26 – 27.

266 NT Gas submission, 14 November 2001, p.27.

Gas quality specifications

The Commission notes Santos' concerns about the gas quality specification proposed for the ABDP. However, the Commission is also aware that its role and expertise is as an economic rather than a technical regulator, and that it has not conducted a full technical review of this issue.

The AGA's Gas Specification Working Group has reached an agreement on a proposed common specification for NSW and Victoria.[267] The Commission requires that NT Gas' access arrangement be amended to ensure that any new specification recommended by the Gas Specification Working Group and approved by the relevant jurisdiction is reflected in the access arrangement for the ABDP. The Commission is of the view that the development and adoption of agreed national standards for the gas industry is a relevant consideration under section 2.24(g) of the Code and outweighs the concerns expressed by Santos about the implications of such a national standard. Therefore the Commission is of the view that a mechanism facilitating the implementation of such standards should be incorporated into the proposed access arrangement.

The Commission recognises that implementation of the revised specification will be subject to obligations under existing service agreements and therefore the proposed amendment takes into account the firm and binding contractual arrangements of the service provider and existing users of the pipeline, as required under section 2.24(b) of the Code.

Amendment FDA4.1

In order for NT Gas' access arrangement for the Amadeus Basin to Darwin Pipeline to be approved, NT Gas must amend the access arrangement to require adoption of a revised gas specification, subject to:

- the enactment of any legislation necessary to facilitate the change in specification;
- recognition and preservation of existing contractual rights and obligations; and
- the specification not precluding continued transportation of gas from existing fields.

Standard service agreement

While schedule 2 of the access arrangement includes key terms and conditions, the proposed access arrangement does not include the standard service agreement which sets out the terms and conditions on which NT Gas will provide the reference service. NT Gas stated that the standard service agreement will be consistent with the access arrangement.

The Commission is aware that NT Gas cannot at this stage be confident that its standard service agreement is consistent with the terms and conditions which the

[267] VENCorp, *Victorian Energy Update*, December 1999, p. 2.

Commission will approve as part of the access arrangement. The Commission expects that users may be primarily guided as to the terms and conditions on which they will gain access to the ABDP by the content of the standard service agreement. To ensure that the interests of prospective users are taken into account under section 2.24(f) of the Code, the Commission requires an amendment to the ABDP access arrangement to make it clear that, in the event that any apparent inconsistency arises, Schedule 2 of the access arrangement prevails over the standard service agreement. This outcome should avoid potential disagreements over the interpretation of the access arrangement and standard service agreement. NT Gas has indicated to the Commission that it accepts this amendment.[268]

Amendment FDA4.2

In order for NT Gas' access arrangement for the Amadeus Basin to Darwin Pipeline to be approved, NT Gas must clearly specify that Schedule 2 of the access arrangement prevails over the standard service agreement.

Prudential requirements

The Commission notes that the provision for access and requests for services and the queuing policy of the access arrangement requires users and prospective users to meet NT Gas' prudential requirements prior to the user requesting a service or assigning a request on a queue.[269]

The prudential requirements that NT Gas requires users and prospective users to meet are not currently specified in the access arrangement. The Commission considers that it is important for users and prospective users to be aware of all the conditions of use of the ABDP. The Commission has assessed the prudential requirements proposed by NT Gas in its response to the *Draft Decision* and considers them reasonable and that the inclusion of this information within the proposed access arrangement's terms and conditions takes into account the interests of potential users under section 2.24(f) of the Code by clearly specifying the prudential requirements that must be satisfied before access will be granted.

Accordingly, the Commission requires the inclusions of the prudential requirements to apply to users and prospective users in NT Gas' access arrangement for the ABDP.

Amendment FDA4.3

In order for NT Gas' access arrangement for the Amadeus Basin to Darwin Pipeline to be approved, NT Gas must include in the access arrangement the prudential requirements set out below:

- The user or prospective user must be resident in, or have a permanent establishment in, Australia;

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268 NT Gas submission, 14 November 2001, p.26.

269 NT Gas Access Arrangement, 25 June 1999, Section 1.4, p.8 and Section 6.2, p.18.

- The user or prospective user must not be under external administration as defined in the Corporations Act or under any similar form of administration in any other jurisdiction; and
- The user or prospective user may be required to provide reasonable security in the form of a parent company guarantee or a bank guarantee or similar security. The nature and extent of the security will be determined having regard to the nature and extent of the obligations of the user or prospective user under the Service Agreement.

4.4 Capacity Management Policy

4.4.1 Code requirements

Section 3.7 of the Code requires an access arrangement to include a statement that the covered pipeline is either a contract carriage pipeline or a market carriage pipeline.

4.4.2 NT Gas' proposal

Section 8 of the access arrangement stated that the ABDP is a contract carriage pipeline.

4.4.3 Commission's Draft Decision

As the access arrangement includes a statement that the ABDP is a contract carriage pipeline, it satisfies the requirements of section 3.7 of the Code.

4.4.4 Submissions by interested parties

No comments were received on this issue.

4.4.5 NT Gas' Response to Draft Decision

No comments were received on this issue.

4.4.6 Commission's Considerations

As the access arrangement includes a statement that the ABDP is a contract carriage pipeline, it satisfies the requirements of section 3.7 of the Code.

4.5 Trading Policy

4.5.1 Code requirements

If a pipeline is a contract carriage pipeline, the access arrangement must include a trading policy that explains the rights of a user to trade its right to another person. The trading policy must, amongst other things, allow a user to transfer capacity:

- without the service provider's consent, if the obligations and terms under the contract between the user and the service provider remain unaltered by the transfer; and

- with the service provider's consent, in any other case.

- Consent may be withheld only on reasonable commercial or technical grounds and the trading policy must specify conditions under which consent will be granted and any conditions attached to that consent.

4.5.2 NT Gas' Proposal

Section 5 of NT Gas' access arrangement stated that users could trade rights in three circumstances. These were:

- a user may make a 'bare transfer' without the consent of NT Gas provided that prior to utilising it the transferee notifies NT Gas of the portion of contracted capacity subject to the bare transfer and of the nature of the contracted capacity subject to the bare transfer.

- a user may only transfer or assign all or part of its contracted capacity other than by way of a bare transfer with the prior consent of NT Gas, which will only be withheld on reasonable commercial or technical grounds, and which may be given subject to reasonable commercial or technical conditions.

- a user may only change the receipt point and/or delivery point specified in a service agreement with the prior consent of NT Gas, which will only be withheld on reasonable commercial or technical grounds, and which may be given subject to reasonable commercial or technical conditions.

4.5.3 Commission Draft Decision

The Commission considers that the trading policy in the access arrangement meets the minimum requirements of the Code, specifically, sections 3.9 to 3.11.

4.5.4 Submissions by interested parties

No comments have been received on this issue.

4.5.5 NT Gas' Response to Draft Decision

No comments have been received on this issue.

4.5.6 Commission's Considerations

The Commission considers that the trading policy in the access arrangement meets the minimum requirements of the Code, specifically, sections 3.9 to 3.11. As a result the Commission is of the view that proposed trading policy is likely to facilitate competition in related markets by enabling trading of capacity in the ABDP and is an outcome consistent with section 2.24(e) of the Code. It is also the Commission's view that the proposed trading policy takes into account the interests of the service provider, users and prospective users pursuant to sections 2.24(a) and (f) and will not compromise the safe and reliable operation of the pipeline.

4.6 Queuing Policy

4.6.1 Code requirements

Sections 3.12 to 3.15 set out the Code's requirements for a queuing policy. An access arrangement must include a queuing policy for determining the priority given to users and prospective users for obtaining access to a covered pipeline and for seeking dispute resolution (under section 6 of the Code). The purpose of the queuing policy is to allocate capacity where there is insufficient capacity to satisfy the needs of all users and potential users that have requested capacity.

Section 3.13 of the Code states that a queuing policy must be set out in sufficient detail to enable users and prospective users to understand in advance how it will operate. It must also, to the extent reasonably possible, accommodate the legitimate business interests of the service provider, and of users and prospective users, and generate economically efficient outcomes. Section 3.14 of the Code allows the regulator to require the queuing policy to deal with any other matter the relevant regulator thinks fit taking into account the matters listed in section 2.24.

4.6.2 NT Gas' Proposal

Section 6 of the access arrangement contained the service provider's queuing policy. Where there is insufficient capacity to satisfy a user's request to obtain a service from NT Gas, a queue will be formed. A queue will include all relevant requests that cannot be satisfied. Where an offer has been made in response to a request received prior to formation of the queue, the request will take first position in the queue.

At the time a request is placed in a new or existing queue, NT Gas will advise the prospective user of:

- its position on the queue;
- the aggregate capacity of requests which are ahead on the queue;
- its estimate of when capacity may become available; and
- the size of any surcharge that may apply to developable capacity.

NT Gas will update these details when the relative position of a request or the timing of available developed capacity changes.

Once in a queue, a prospective user may reduce but not increase the capacity sought in its request. An assignment of a request can be made to a bona fide purchaser of the prospective user's business or assets.

A request for service may lapse and be removed from the queue if:

- the prospective user does not respond to NT Gas' request for confirmation of the request within the specified 14 days;

- the prospective user notifies NT Gas that it does not want to proceed with the request; or

- the entity to whom the prospective user assigns its request does not meet NT Gas' prudential requirements.

A request will not lapse in the event that there is a dispute. The request will retain its priority until the dispute is resolved in accordance with the Code.

When capacity is made available which meets the requirements of any request in a queue, that capacity will be progressively offered to each prospective user in the queue in order of priority. NT Gas will advise each of those prospective users of its plans to make capacity available, and the terms and conditions on which the capacity will be available.

A prospective user will have 30 days after an offer is made to enter into a service agreement, failing which the request will lapse or lose priority to those entering into such a service agreement.

Priority of Prospective Users in Obtaining Services

Clause 6.4 sets out the manner in which priority is to be assigned to requests where a queue has been formed under clause 6.1. The fourth dot point in clause 6.4 provides that where a user exercises a contractual right in force as at 25 June 1999 to increase capacity reservation under its existing service agreement, that increase will be treated as a request and will be placed at the head of the queue, notwithstanding that priority would otherwise be accorded to any earlier requests.

In relation to prospective users, the proposed queuing policy is as follows:

- the earliest date a complete request is received by NT Gas; and

- if the request is for a reference service it will have priority over a request for a negotiated service or a request for an interruptible service.

4.6.3 Commission's Draft Decision

The Commission stated in its *Draft Decision* that it was concerned that the fourth dot point of clause 6.4 does not reasonably accommodate the legitimate business interests of prospective users because it establishes a principle in the queuing policy where they could be denied access to capacity. Such a principle has the potential to diminish competition in downstream markets in the future.

Further, the Commission stated that it was concerned that clause 6.4 could become established in the access arrangement and form the basis of future access arrangements. The Commission required the following amendment:

Proposed Amendment 4.8

In order for NT Gas' access arrangement for the Amadeus Basin to Darwin Pipeline to be approved, NT Gas must remove the fourth dot point of clause 6.4.

4.6.4 Submissions by interested parties

Woodside submitted that pre-emptive rights to capacity for existing users could be used to restrict access for new entrants. Woodside stated that at the very least existing users should need to demonstrate a business requirement for that capacity.[270] NTPG supported Woodside's submission and suggested that the inclusion of the fourth dot point of clause 6.4 would encourage strategies designed to hinder competition.[271]

PWC submitted that deletion of the fourth dot point of paragraph 6.4 of NT Gas' Access Arrangement would give rise to inconsistencies between NT Gas' obligations under the Access Arrangement and PWC's rights under its long term gas transportation agreement with NT Gas entered into in 1985.[272]

4.6.5 NT Gas' Response to Draft Decision

NT Gas stated that:

> The Commission's view that removal of the provision would not deny existing users of a contractual right[273] is incorrect. The proposed amendment would deprive a person of an existing contractual right (which is not an Exclusivity Right), and it is therefore contrary to section 2.25 of the Code.[274]

4.6.6 Commission's Considerations

NT Gas proposed in clause 6.4 of the access arrangement, that an existing user with a contractual right in force as at 25 June 1995 will have pre-emptive rights over capacity reservation. Sections 2.25, 2.47 and 6.18 of the Code all state that the regulator or arbitrator must not make a decision that has the effect of depriving a person of an existing contractual right, 'other than an Exclusivity Right which arose on or after 30 March 1995'. The Commission has examined the pre-existing contracts and has been unable at this stage to identify any provisions, which would be defined as an exclusivity right.

The Commission has considered the submissions of Woodside and NTPG, and is concerned that the fourth dot point of clause 6.4 may, in certain circumstances, deny potential users from gaining access to the pipeline. The Commission considers that the fourth dot point of clause 6.4 has the potential to restrict competition in downstream markets.

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270 Woodside submission of 9 September 1999, p.1.

271 NTPG submission of 2 August 2001, p.6 – 7.

272 PWC submission of 4 October 2001, p.7.

273 *Draft Decision*, page 115.

274 NT Gas submission, 14 November 2001, p.27.

However, the Commission has considered the submissions of NT Gas and PWC, and considers that it would be detrimental to NT Gas for the access arrangement to conflict with its existing contractual obligations. While the Commission interprets the contract differently to NT Gas and PWC, it is not absolutely clear that NT Gas would not be adversely affected by the removal of the fourth dot point of clause 6.4.

Under sections 2.24(f) and (a) of the Code, the regulator must have regard to not only the interests of users and prospective users, but to the service provider's legitimate business interests, and its investment in the covered pipeline. Due to the ambiguity of NT Gas' obligations under its contract with PWC and the potential to compromise NT Gas' position of by removing the fourth dot point of clause 6.4, the Commission has decided not to require removal of the fourth dot point of clause 6.4 for the first access arrangement period. It is also the Commission's view that the public benefit under section 2.24(f) of the Code associated with the continued operation of the GSA, and the lease agreement is a relevant consideration. As such, the Commission is also of the view that the fourth dot point should not be removed.

The Commission notes however that if this dot point is used to restrict access to the pipeline or to hinder competition, the relevant party(s) may be found to have breached section 13 of the Gas Pipelines Access Law and/or other legislation.

4.7 Extensions and Expansions policy

4.7.1 Code requirements

The Code (section 3.16) requires an access arrangement to have an extensions/expansions policy. The policy is to set out the method to be applied to determine whether any extension to, or expansion of the capacity of the pipeline will be treated as part of the covered pipeline. A service provider is also required to specify the impact on reference tariffs of treating an extension or expansion as part of the covered pipeline.[275] In addition, an extensions/expansions policy must outline the conditions on which the service provider will fund new facilities and provide a description of those new facilities.

The Code's requirements relating to new facilities investment are contained in sections 8.15 – 8.19 of the Code. The Code (sections 8.15-8.16) allows for the capital base to be increased to recognise additional capital costs incurred in constructing new facilities for the purpose of providing services. Under section 8.16 of the Code, the amount of the increase is the actual capital cost provided that:

- the investment is prudent in terms of efficiency;
- it is in accordance with accepted good industry practice; and
- it is designed to achieve the lowest sustainable cost of delivering services (section 8.16(a)).

[275] For example, reference tariffs may remain unchanged, but a surcharge may be levied on incremental users.

One of the following must also be satisfied (section 8.16(b)):

i the incremental revenue is not expected to exceed the cost of the investment; or

ii the service provider and/or users must satisfy the relevant regulator that the new facility has system wide benefits (justifying higher tariffs for all users); or

iii the new facility is necessary to maintain the safety, integrity or contracted capacity of services.

Reference tariffs may be determined on the basis of forecast investment during the access arrangement period provided that such investment is reasonably expected to pass the requirements of section 8.16 of the Code when the investment is forecast to occur (section 8.20 of the Code).

4.7.2 NT Gas' proposal

The extensions and expansions policy is described in Section 7 of NT Gas' access arrangement. NT Gas proposes that in the event that it elects to extend the pipeline, then that extension will, at the election of NT Gas, be treated as part of the ABDP for the purposes of this access arrangement. Reference tariffs for existing delivery points will not be affected by any extension.

In the event that NT Gas expands the capacity of the pipeline, NT Gas will elect either to treat the expanded capacity as:

- part of the ABDP for the purposes of this access arrangement and NT Gas will exercise its discretion to submit proposed revisions to this access arrangement under section 2 of the Code; or

- not part of the ABDP for the purposes of this access arrangement and NT Gas will lodge a separate access arrangement in respect of any of that expanded capacity which is not subject to contract.

4.7.3 Commission's Draft Decision

The Commission's *Draft Decision* stated that the extensions and expansions policy proposed was inconsistent with the principles set out in section 2.24 of the Code. In particular, the Commission was not satisfied that section 2.24(e) of the Code had been met.

Section 2.24(e) of the Code states:

(e) the public interest, including the public interest in having competition in markets (whether or not in Australia.)

Accordingly, the Commission proposed the following amendment to NT Gas' access arrangement.

Proposed Amendment 4.9

In order for NT Gas's access arrangement for the Amadeus Basin to Darwin Pipeline to be approved, NT Gas must specify in the access arrangement that it will obtain the

Commission's consent before electing to omit new facilities (either extensions or expansions) from the covered pipeline.

4.7.4 Submissions by interested parties

Nabalco submitted that the expansions and extensions policy was only suitable for a minor change and if a major expansion occurred then the entire access arrangement would need to be reviewed.[276] NTPG endorsed the Commission's proposed amendment that would require NT Gas to obtain the Commission's consent before electing to omit new facilities from the covered pipeline.[277]

4.7.5 NT Gas' Response to Draft Decision

NT Gas is opposed to the amendments proposed in the Commission's *Draft Decision*. With respect to extensions:

> The Code does not assume that all extensions or expansions are automatically covered, and also does not require a service provider to obtain the regulator's approval whether to include an extension or expansion as part of the covered pipeline. Additionally, if NT Gas were to elect not to include an extension as part of the covered pipeline, any person can apply for coverage of the extension. Both of these matters were clearly recognised by the Commission in the *Draft Decisions* on the Carpentaria Gas Pipeline and the Roma to Brisbane Pipeline.
>
> The difference between the proposed access arrangement and the amendment is that the Commission rather than the service provider will make the decision as to whether an extension is or is not covered. This is inconsistent with the regime under the Code under which:
>
> - the access arrangement may permit the service provider to elect whether to voluntarily cover the extension; and
>
> - if the service provider does not elect to voluntarily cover the extension, the decision on coverage is made by the Minister.
>
> Accordingly, NT Gas does not agree with the proposed amendment, as it is unreasonable and unnecessary.[278]

With respect to expansions:

> Given that NT Gas has proposed – at a minimum – voluntary coverage of all capacity which is not subject to contract, the Commission has no basis to be concerned that "if such an expansion were undertaken, the Commission would want to ensure that the pipeline owner was not in a position to exploit market power". NT Gas also submits that this concern appears more relevant to the Commission's role as regulator under the Trade Practices Act than to the exercise of its discretion under the Code.
>
> The proposed access arrangement is fully consistent with the Code, which recognises that the service provider is entitled to discretion in the manner in which the access arrangement treats expansions. However, the Draft Decision effectively proposes that

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276 Nabalco submission , 9 September 1999, p. 2.

277 NTPG Submission, 2 August 2001, p.6.

278 NT Gas submission, 14 November 2001, p.28.

> the Commission, not NT Gas or the Minister should decide whether expanded capacity is to be considered part of the covered pipeline. This is inconsistent with the Code's recognition of the discretion of the service provider in developing the expansions policy. It is also inconsistent with the framework under the Code whereby, in the absence of (effectively) voluntary coverage by the service provider, the decision on coverage is made by the Minister.
>
> NT Gas does not agree to this amendment, as it is unnecessary and unreasonable.[279]

4.7.6 Commission's Considerations

In assessing the access arrangement lodged by the service provider the Commission must take into account the factors outlined in section 2.24 of the Code. Section 2.24 factors include: the service provider's legitimate business interests (a), the public interest (e), the economically efficient operation of the covered pipeline (d) and the interests of users and prospective users (f).

In considering whether NT Gas' proposed extensions/expansions policy is reasonable, it is necessary to consider the environment in which any expansion or extension would take place. The Commission considers that there is a possibility that the pipeline may need to be expanded to meet the growing gas demand in Darwin. The pipeline is close to or at capacity currently. As such, a need to expand the pipeline could arise if Timor Sea gas does not arrive in Darwin. In such a scenario, subject to the availability of suitable gas reserves, prospective users would have little choice but to finance an expansion of the ABDP if they required gas.

In the event of excess demand, NT Gas may be able to exercise a degree of market power in setting the terms and conditions for an expansion if it is not, in its entirety, subject to an access arrangement. Potentially, NT Gas could be in a position to extract monopoly rents by pricing expansions just below the point where it would no longer be commercially viable for a user or prospective user to expand the pipeline.

Such behaviour may discourage investment and entry into downstream markets, and is likely to affect the competitiveness of entrants in downstream markets and produce an outcome that would be contrary to the public interest under section 2.24(f) of the Code. As a result, where entry does occur, new entrants may be unable to act as a competitive constraint on incumbents because their costs would be higher if they are paying more for gas transportation. Effective competition in downstream markets, and the resulting efficiency gains, would not be achieved. The service provider would capture monopoly rents that would otherwise be passed onto business and households in the form of lower prices. This may impact on the Northern Territory's economic growth potential.

The Commission notes the comments by NT Gas with respect to the options available for Code coverage of a pipeline under the Code in light of the proposed amendment contained within the *Draft Decision*. Specifically, the Code provides that:

> 3.16(a) (for example, the Extensions/Expansions Policy could provide that the Service Provider may, with the Relevant Regulator's consent, elect at some pome point in time whether of

279 NT Gas submission, 14 November 2001, p.28-9.

> not an extension or expansion will be part of the Covered Pipeline or will not be part fo the Covered Pipeline);

It is the Commission's view that requiring the Commission's consent before an expansion becomes part of the Code is not unreasonable or unnecessary, as such an option it is provided for in the Code. Therefore the Commission is of the view that in addition to other coverage mechanisms, including declaration, it is a relevant consideration under section 8.10(g) to require that the expansion policy incorporate a coverage provision already permitted under the Code.

The Commission has sought to provide an alternative to the option of coverage by providing NT Gas with the choice of lodging an access arrangement for the expanded part of the ABDP. The Commission considers that its proposed alternative allows for NT Gas to lodge an access arrangement for the expanded part of the pipeline.

It is the Commission's view that coverage of the expanded part of the pipeline is in the public interest by facilitating competition in related markets through access to additional capacity in the ABDP. This outcome is consistent with section 2.24 (e) of the Code and is also in the interests of users and prospective users, under section 2.24 (f) of the Code, who may seek access to the ABDP.

The Commission rejects the NTPG's proposal for the entire access arrangement to be reviewed should a major expansion or extension be undertaken. It is the Commission's view that an extension or expansion is likely to be undertaken if a major event such as the development of gas producing fields off Australia's northern coast were to proceed. In such circumstances the proposed trigger mechanism is likely to be activated and that opportunity would provide scope to review the access arrangement. It is the Commission's view that a trigger mechanism would therefore provide adequate protection to the interests of users under section 2.24(f) of the Code.

Accordingly, the Commission considers that under section 2.24 of the Code the economically efficient operation of the covered pipeline (d); the public interest (e), including the public interest in having competition in markets; and the interests of users and prospective users (f) each requires that expansions to the pipeline should be covered, unless the regulator consents otherwise. Coverage of new facilities would entitle prospective users to make use of the dispute resolution processes provided in section 6 of the Code. The expansions policy proposed by NT Gas provides for expansions under contract not to be subject to an access arrangement. This issue is addressed by the amendment below.

In terms of extensions, it is not clear that NT Gas would have as much market power, that is capacity to extract monopoly rents from inefficient prices, as in the case of expansions, because other pipeline companies would be able to construct geographical extensions to the pipeline. This is because NT Gas' economies of scale and scope in terms of expanding the existing pipeline are substantially greater than for extending the pipeline. In these circumstances, the Commission considers that NT Gas' proposal with respect to extensions is appropriate.

The Commission requires the following amendment to be made in respect of the expansions policy.

Amendment FDA4.4

In order for NT Gas's access arrangement for the Amadeus Basin to Darwin Pipeline to be approved, NT Gas must amend section 7.2(b) and insert (c) to its proposed access arrangement to read:

(b) that the expanded capacity will not be treated as part of the pipeline for the purposes of this Access Arrangement and NT Gas will lodge a separate access arrangement in respect of that expanded capacity; or

(c) that the expansion will not be covered, subject to the consent of the Commission prior to the expansion coming into service.

4.8 Review and expiry of the access arrangement

4.8.1 Code requirements

Section 3.17 of the Code requires an access arrangement to include a date upon which the service provider must submit to the regulator a revised access arrangement (revisions submission date) and a date upon which the revisions are intended to commence (revisions commencement date).

In deciding whether these two dates are appropriate, the regulator must have regard to the objectives contained in section 8.1 of the Code. Having done so, the regulator may require an amendment to the proposed access arrangement to include earlier or later dates. The regulator may also require that specific major events be defined as a trigger that would oblige the service provider to submit revisions before the revisions submission date (section 3.17(ii)).

An access arrangement period accepted by the regulator may be of any duration. However, if the period is greater than five years, the regulator must consider whether mechanisms should be included to address the potential risk that forecasts, on which terms of the proposed access arrangement are based, subsequently prove to be incorrect (section 3.18 of the Code). The Code provides examples of such mechanisms for guidance. Thus a regulator could consider triggers for early submission of revisions based on:

- divergence of the service provider's profitability or the value of services reserved in contracts from a specified range; or
- changes to the type or mix of services provided.
- The regulator could require a service provider to return to users some or all revenue of profits in excess of a certain amount.

Finally, the revisions commencement date is not a fixed date. The date is subject to variation at the time the regulator approves the revisions pursuant to section 2.48 of the Code. This section states in part:

> Subject to the Gas Pipelines Access Law, revisions to an access arrangement come into effect on the date specified by the Relevant Regulator in its decision to approve the revisions (which date must not be earlier than either a date 14 days after the day the decision was made or…. The revisions Commencement Date).

4.8.2 NT Gas' Proposal

NT Gas initially proposed to submit revisions to the access arrangement four years and six months from the commencement of this access arrangement, and that the revisions would commence on the later of;

- the date being 6 months after the revisions submission date; and
- the date on which the approval by the regulator of the revisions to the access arrangement takes effect under the Code.

4.8.3 Commission's Draft Decision

NT Gas has proposed a revisions submission date and a revisions commencement date in accordance with the requirements of the Code.

An access arrangement for the initial access arrangement period will commence in accordance with section 2.26 of the Code only after the Commission is satisfied that it meets the minimum requirements of the Code.

4.8.4 Submissions by interested parties

Woodside contended that the review commencing after 4 years and 6 months is much too late, and argue;

> The review of this Access Arrangement should be completed at least two years from expiry to provide certainty to prospective investors after the initial five-year period.[280]

Nabalco suggested that the term and review section should contain a trigger mechanism to review the access arrangement prior to the revisions submission date. It contended a suitable trigger would include Nabalco entering into an agreement with a gas supplier for supply of gas to Gove.[281]

4.8.5 NT Gas' Response to Draft Decision

In a letter dated 17 April 2002, NT Gas requested that the Commission consider an access arrangement of ten years duration (rather than five) to coincide with the expiry date of the lease, 17 June 2011. NT Gas presented the following arguments in support of a longer access arrangement period:[282]

> Alignment of the regulatory period with the lease term seems appropriate for the following reasons:

280 Woodside submission, 9 September 1999, p. 1.

281 Nabalco submission, 9 September 1999, p. 2.

282 Letter from Agility Management, on behalf of NT Gas, to Commission staff, 17 April 2002.

- The lease finance costs represent a major component of NT Gas' costs and these are, subject to interest rate fluctuations, effectively "fixed" until the expiry of the lease,
- The lease finance costs have very direct impact on the revenues which must be received for NT Gas to remain viable and thus on the level of third party tariffs,
- The foundation contracts for the pipeline expire at that time.
- Such alignment would also reduce overall regulatory costs, which is a significant consideration given the small quantities of third party access which can reasonably be expected to be available prior to the expiry of the foundation contracts.

NT Gas' opposition to a review trigger in the context of a five-year access arrangement period was presented in section 4.2.6. However, following discussions with the Commission and in the context of a ten-year access arrangement period, NT Gas agreed to the inclusion of a trigger mechanism relating to significant changes in the gas industry in the NT.[283]

4.8.6 Commission's Considerations

The Commission acknowledges that a ten-year access arrangement is now NT Gas' preferred option, and in this case, that there is little to be achieved by a scheduled review in five years. This is due to the lease arrangement and other existing contractual obligations, and the limited scope for variance from forecasts as all firm capacity on the pipeline is fully contracted. It is the Commission's view that under section 2.24(a) and (b) these considerations represent the legitimate interests of the service provider and its binding obligations under the GSA and the lease agreement. It is in the broader public interest that the ongoing operation of these agreements be taken into account under section 2.24(f) of the Code given the benefits associated with the construction and operation of the pipeline, as discussed previously.

However, in approving an access arrangement of more than five years duration, section 3.18 of the Code requires the Commission to consider '… whether mechanisms should be included to address the risk of forecasts on which the terms of the access arrangement were based and approved proving incorrect.'

The Commission has considered requiring a mechanism under section 3.18 of the Code. However, the reasons justifying an access arrangement of more than five years – foundation contracts fully booking the firm capacity of the pipeline until 2011, and limited scope for variation from forecasts – lead the Commission to consider mechanisms under section 3.18 of the Code unnecessary in this instance.

Notwithstanding this, the Commission believes that there is the potential for substantial change in circumstance between now and 2011 if a major new source of gas entered the market, such as Timor Sea gas. Should Timor Sea gas be available in Darwin, it is likely that the services demanded on the ABDP by the market would change[284] and that it would be appropriate to review the access arrangement. It is the Commission's view

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283 Email from Agility Management, on behalf of NT Gas, to Commission staff, 5 June 2002.

284 See section 4.2.7 for discussion of back haul services.

that the inclusion of a trigger mechanism can provide for the protection of the interests of users and prospective users, such as Nabalco, under section 2.24(f) of the Code by allowing a reassessment of the access arrangement against changing circumstances.

Therefore, the Commission has decided to require a trigger under section 3.17 of the Code, as set out in the amendment below. The amendment also specifies the Revisions Submission Date of 1 January 2011. As noted previously, NT Gas has indicated its support for the inclusion of a specific major events trigger mechanism in the context of a ten-year access arrangement.

An access arrangement for the initial access arrangement period will commence in accordance with section 2.26 of the Code, after the Commission is satisfied that it meets the minimum requirements of the Code.

Amendment FDA4.5

In order for NT Gas' access arrangement for the Amadeus Basin to Darwin Pipeline to be approved, NT Gas must amend clause 9.2 of the access arrangement:

- to specify 1 January 2011 as the Revisions Submission Date; and
- to include the following trigger mechanism:

  NT Gas is required to submit revisions to this access arrangement within one month of receiving written notification by the Commission that one of the following major events has occurred:

  (i) the interconnection of another pipeline with the ABDP; or

  (ii) the introduction of a significant new source of gas supply to one of the ABDP's markets;

  that substantially changes the types of Services that are likely to be sought by the market or has a substantial effect on the direction of the flow of natural gas through all or part of the pipeline.

5. Information provision and performance indicators

5.1 Information provision

5.1.1 Code requirements

In conjunction with its proposed access arrangement, a service provider is required to submit access arrangement information. The access arrangement information must contain sufficient information to assist all parties in understanding the proposed access arrangement.

According to section 2.7 of the Code, the access arrangement information provided may include any relevant information, but must at least contain the categories of information described in Attachment A to the Code, which is summarised in Box 5.1 below.

Box 5.1 Summary of Attachment A information

The information required is divided into six categories:

Category 1: access and pricing principles

Tariff determination methodology; cost allocation approach; and incentive structures.

Category 2: capital costs

Asset values and valuation methodology; depreciation and asset life; committed capital works and planned capital investment (including justification for); rates of return for equity and debt; and debt/equity ratio assumed.

Category 3: operations and maintenance costs

Fixed versus variable; cost of services by others; cost allocation between, for example, pricing zones, and cost categories.

Category 4: overheads and marketing costs

Costs at corporate level; regulated versus unregulated; cost allocation between, for example, pricing zones, and categories of assets.

Category 5: system capacity and volume assumptions

Description of system capabilities; map of piping system; average and peak demand; existing and expected future volumes; system load profiles and customer numbers.

Category 6: key performance indicators

Indicators used to justify ‘reasonably incurred’ costs.

Under section 2.8 of the Code, information included in the access arrangement information may be categorised or aggregated to the extent necessary to ensure that disclosure of the information is not in the opinion of the relevant regulator, unduly harmful to the legitimate business interests of the service provider, a user or prospective user.

If the relevant regulator is not satisfied that the access arrangement information meets the requirements of the Code, it may, of its own volition, require the service provider to make changes to the access arrangement information. Likewise, if requested to do so by any person, the relevant regulator must review the adequacy of the access arrangement information.

If the relevant regulator requires the service provider to change the access arrangement information, it must specify the reasons for its decision and allow the service provider a reasonable time to make the changes and resubmit the access arrangement information.

This chapter relates specifically to access arrangement information, which is provided for users and prospective users. However, it is important to note that the regulator also has much wider information gathering powers under the *Gas Pipelines Access (Northern Territory) Act 1998* (GPAL). If the regulator has reason to believe that a person has information or a document that may assist the regulator in the performance of any of the regulator's prescribed duties under the GPAL, the regulator may require that person to provide the information or a copy of the document to it.[285] Section 2.8 of the Code states that nothing in that section limits the regulator's power under GPAL to obtain information, including information in an uncategorised or unaggregated form. The Code and the GPAL place limitations on the discretion of the regulator to disclose information received that has been identified to be of a 'confidential or commercially sensitive nature'.[286]

5.1.2 NT Gas' proposal

NT Gas submitted access arrangement information in conjunction with the access arrangement on 25 June 1999. In response to a request by the Commission pursuant to section 2.9(a) of the Code, NT Gas submitted further access arrangement information on September 1999. This information was necessary to assess the proposed access arrangement and to assist in the preparation of the *Draft Decision*.

5.1.3 Submissions by interested parties

There were no submissions on this issue.

5.1.4 Commission's Draft Decision

Following receipt of NT Gas' access arrangement and access arrangement information on 25 June 1999, the Commission assessed the access arrangement information for compliance with the requirements of 2.6 and 2.7 of the Code. Pursuant to section 2.9(a) of the Code, the Commission determined that the access arrangement information did not satisfy those requirements, and decided to seek further information from NT Gas by issuing a section 41 notice pursuant to the GPAL.

On 20 August 1999, the Commission issued a notice under section 41 of the GPAL on NT Gas for required information. This information included: the existing transportation contracts for the ABDP; a copy of the independent auditors' report of the asset valuation and electronic copy of all financial models used in developing the access arrangement information. In addition to issuing the section 41 notice, the

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[285] Section 41, *Gas Pipelines Access (NSW) Act 1988*.

[286] Section 7.11 and 7.12 of the Code and section 42, *Gas Pipelines Access (NSW) Act 1988*.

Commission sought information from NT Gas on a number of issues, including justification for NT Gas' proposed WACC of 11 per cent and accelerated depreciation of the regulatory asset base.

The Commission stated in the *Draft Decision* that sufficient information was provided in total by the access arrangement information and the response by NT Gas to the section 41 notice issued under the GPAL to satisfy the information disclosure requirements of the Code.

5.1.5 Submissions from interested parties

There were no submissions on this issue.

5.1.6 Commission's Considerations

Following the release of the *Draft Decision* the Commission sought further information from NT Gas in relation to costing and financial data necessary to assess the proposed access arrangement and take account of changes in relevant factors since the issuance of the *Draft Decision*. As a result, on 11 July 2001 the Commission issued a notice pursuant to section 41 of the GPAL to NT Gas for the purpose of obtaining information necessary to assess the proposed access arrangement for the ABDP and determine aspects of the *Final Decision*. NT Gas complied with its obligations under the GPAL and supplied the requested information, some of this information needs to be included in the final access arrangement information document.

The Commission assessed the information provided by NT Gas in its entirety and concluded that the original access arrangement information, together with the additional information, satisfied the requirements of the Code with respect to the proposed access arrangement. Changes proposed in this *Final Decision* will require further revisions to the access arrangement information. This will be necessary to reflect the provision of the most to up-to-date information that was supplied by NT Gas, to the Commission, to enable the completion of the *Final Decision*.

It is the Commission's view that under section 2.24(f) of the Code the interest of users and prospective users are served by the revision of the access arrangement information to reflect the most to up-to-date values that form the basis of reference tariffs. The Commission therefore requires NT Gas to comply with proposed amendment FDA5.1

Amendment FDA5.1

For the access arrangement to be approved, the Commission requires NT Gas to revise its access arrangement information so that it is consistent with the most recent information provided to the Commission as part of the completion of the *Final Decision,* and incorporate relevant amendments specified in this *Final Decision*.

5.2 Key performance indicators

5.2.1 Code requirements

The Code identifies the need for key performance indicators (KPIs) to be disclosed by service providers to interested parties. Category 6 of Attachment A of the Code lists the following relevant items:

- industry KPIs used by the service provider to justify 'reasonably incurred' costs; and
- service provider's KPIs for each pricing zone, service or category of asset.

Section 8.6 of the Code allows the regulator to 'have regard to any financial and operational performance indicators it considers relevant in order to determine the level of costs within the range of feasible outcomes under section 8.4 that is most consistent with the objectives contained in section 8.1 of the Code.' The regulator must then identify the indicators and provide an explanation of how they have been taken into account (section 8.7 of the Code).

5.2.2 NT Gas' proposal

NT Gas identified a number of limitations on the usefulness of publicly available information relating to the performance of the Australian natural gas transmission industry.[287] In particular, NT Gas noted that much of the information publicly available relates to publicly owned pipelines prior to their privatisation, and that private companies have declined to release performance information on the basis of commercial sensitivity and restrictions on disclosure. Further, NT Gas noted the difficulty of 'normalising' pipelines for such things as diameter, length, geography and topography of location and operational characteristics, to yield meaningful comparisons.

Nevertheless, NT Gas recognised the need for the regulator to benchmark performance and has provided a number of measures, which it considers will contribute to the development of meaningful industry performance measures over time.

Operating Costs

NT Gas' total operating costs for the year ending 30 June 1999 were estimated to be $6.4m. NT Gas considered that $6.4m was below what it considered to be an indicative operating cost, that is $6.7m, as determined by the application of industry's accepted 'rules of thumb'.

NT Gas also provided some analysis based on comparisons with;

- estimated total operating costs ($/1000km) of other Australian pipelines; and
- operating costs of US pipelines.

[287] Access Arrangement Information, p. 43

NT Gas acknowledges that the information provided for some of these pipelines is dated and that there are significant differences in these pipeline systems. However, NT Gas stated that total operating costs for the ABDP are efficient.

5.2.3 Submissions by interested parties

PWC criticised the use of key performance indicators which compare NT Gas' proposed operating and maintenance expenditure for the ABDP with other Australian and US pipelines. PWC considered that it is 'overly simplistic' and 'meaningless' to compare operating costs between pipelines on a 'dollars per 1000 km' basis. In particular:

> 'The figure produced provides no meaningful insight about NT Gas' efficiency in operating the pipeline, compared with other Pipelines. There are no benchmarks. The primary reason for this is the wildly varying conditions and configurations of each Pipeline apart from length which impact on operating costs, such as pipe diameter, throughput, number of compressors, terrain, location (remote/urban) and the number of users'. [288]

5.2.4 Commission's *Draft Decision*

The Commission noted in its *Victorian Final Decision* the challenges in identifying KPIs and benchmarks especially in a newly deregulated commercial environment such as the Victorian natural gas industry.[289] At that stage the Commission stated its intention to work closely with the Victorian service providers to establish appropriate KPIs but that in the short to medium term, it would have regard to financial performance indicators pursuant to section 8.6 of the Victorian Code. The Commission also considered the use of benchmarks such as load factor and energy delivered per employee which are set out by the Steering Committee on National Performance Monitoring of Government Trading Enterprises as a basis for developing non-financial indicators for Transmission Pipelines Australia, now GasNet's Principal Transmission System in Victoria.

However, arrangements whereby NT Gas has contracted activities out to other companies in the AGL Group create particular difficulties when using of some of the benchmarks mentioned above. As NT Gas has no employees, 'per employee' measures are not directly available. Further, to the extent these contracted entities are primarily engaged in activities unrelated to the ABDP, there may be factors such as economies of scale and scope that blur comparisons with pipelines that would on face value appear to be comparable with the ABDP (for example, stand-alone pipelines of similar diameter and length).

The Commission also recognises the limitations of KPI information noted by NT Gas. Nevertheless, the Commission welcomes NT Gas' contribution to the available body of benchmarking information. Based on the information provided by NT Gas regarding operating costs, the ABDP's performance over the long term appears reasonable.

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[288] Clayton Utz, 17 November 1999, NT Government and PWC submission to the ACCC on Access Arrangement for the Amadeus Basin to Darwin Gas Pipeline, p. 8

[289] ACCC, *Final Decision* – Victoria, p. 157.

There were no submissions on the issue of KPIs or financial indicators received in response to the *Draft Decision*.

6. Final decision

Pursuant to section 2.16(a)(ii) of the Code, the Commission does not approve NT Gas' proposed access arrangement for the ABDP.

Pursuant to section 2.16(a)(ii) of the Code, the Commission requires NT Gas to resubmit a revised access arrangement by 15 January 2003.

The amendments (or as appropriate, the nature of amendments) that would have to be made in order for the Commission to approve the proposed access arrangements are recorded in this *Final Decision*.

As stated in chapter 1, this document sets out the Commission's *Final Decision* on the access arrangement. It does not address those provisions of the original access arrangements that have since been superseded or withdrawn.

Australian Competition and Consumer Commission

Annexure A - Submissions received by the Commission

Submissions received by Commission in response to the Issues Paper (August 1999)

Note: In some cases, additional information has been provided to the Commission on a confidential basis.

Interest	Abbreviation	Date of Document
Woodside Energy Ltd and Shell Development (Australia) Pty Ltd,	**Woodside**	9 September 1999
Nabalco Pty Ltd	Nabalco	9 September 1999
NT Power Group Pty Ltd,	NTPG	12 September 1999
Santos Ltd,	Santos	17 September 1999
Northern Territory of Australia and Power and Water Authority	PWC	17 November 1999
Northern Territory of Australia and Power and Water Authority (now Power and Water Corporation)	PWC	29 February 2000

Submissions received by Commission in response to *Draft Decision* (May 2001)

Note: In some cases, additional information has been provided to the Commission on a confidential basis.

Interest	Abbreviation	Date of Document
Santos Ltd	**Santos**	8 June 2001
NT power Group Pty Ltd	**NTPG**	12 August 2001
Northern Territory of Australia and Power and Water Authority (now Power and Water Corporation)	**PWC**	4 October 2001
Northern Territory Government	**NT Government**	4 October 2001

Annexure B - Breakdown of the ORC valuations for each Zone

ORC valuations for each Zone as at 1 July 2001

	Zone 1: Amadeus Basin to Warrego	**Zone 2: Warrego to Mataranka**	**Zone 3: Mataranka to Darwin**	**Total**
Transmission pipelines	$135,100	$89,200	$72,100	$296,400
Compressors	$17,900	$17,900		$35,800
Regulating, metering, odourisation	$2,900	$800	$3,600	$7,300
SCADA & communications	$2,400	$1,600	$1,300	$5,300
Operations facilities	$5,100	$3,500	$2,500	$11,100
Sub total	$163,400	$113,000	$79,500	$355,900
Interest during construction	$8,200	$5,600	$4,000	$17,800
Total	**$171,600**	**$118,600**	**$83,500**	**$373,700**

Note: native title allowance included under pipelines

Public version of Annexure C – Initial capital base valuation

The content of this annexure is confidential to NT Gas Pty Ltd.

Public version of Annexure D – Legitimate business interests and existing obligations

The content of this annexure is confidential to NT Gas Pty Ltd.

Public version of Annexure E – Once-off tariff adjustment

The content of this annexure is confidential to NT Gas Pty Ltd.

Public version of Annexure F – Purchase Price

The content of this annexure is confidential to NT Gas Pty Ltd.