Australian Competition and Consumer Commission

Submission to the Productivity Commission Review of the Gas Access Regime

15 September 2003

CONTENTS

Abbreviations

AA	Access Arrangement
AAI	Access Arrangement Information
ACCC	Australian Competition and Consumer Commission
ACG	Allens Consulting Group
ACT	Australian Capital Territory
AER	Australian Energy Regulator
AGA	Australian Gas Association
AGL	Australian Gas Light company
AGLGN	Australian Gas Light Gas Networks
APIA	Australian Pipeline Industry Association
APPEA	Australian Petroleum Production and Exploration Association
APT	Australian Pipeline Trust
ARC	Administrative Review Council
AusCID	Australian Council for Infrastructure Development
BHP	Broken Hill Proprietary company
CAPM	Capital Asset Pricing Model
CMP	Competitive Markets Principle
CoAG	Council of Australian Governments
Code	*National Third Party Access Code for Natural Gas Pipeline Systems*
CPI	Consumer Price Index
CRNG & TAI	Central Ranges Natural Gas and Telecommunications Association Incorporated
Cth	Commonwealth
CWP	Central West Pipeline
DGG	Draft Greenfield's Guideline
DORC	Depreciated Optimised Replacement Cost
DRP	Draft Regulatory Principles
EBIT	Earnings before Interest and Tax
EGP	Eastern Gas Pipeline
ESC	Essential Services Commission of Victoria
GJ	giga joule
GPAL	Gas Pipelines Access Law
GPO	Gas Pricing Order
ICB	Initial Capital Base
IPART	Independent Pricing and Regulatory Tribunal (NSW)
LMGSG	Lodden Murray Gas Supply Group
LPG	Liquefied Petroleum Gas
MAPS	Moomba to Adelaide Pipeline System
MCE	Ministerial Council on Energy
MERoR	Mean Expected Rate of Return
MHA	Member of the House of Assembly
MRP	Market Risk Premium
MSP	Moomba to Sydney Pipeline
NAM	Negotiate Arbitrate Model

NCC	National Competition Council
NECA	National Electricity Code Administrator
NECG	Network Economics Consulting Group
NEM	National Electricity market
NER	National Energy Regulator
NERA	National Economic Research Associates
NFF	National Farmers Federation
NPV	Net Present Value
NSW	New South Wales
NT	Northern Territory
NZ	New Zealand
OECD	Organisation for Economic Cooperation and Development
ORG	Office of the Regulator General (Vic)
Parer Review	COAG Energy Market Review
Part IIIA	Part IIIA (Access to Services) of the *Trade Practices Act 1974* (Cth)
Part XIC	Part XIC (Telecommunications Access Regime) of the *Trade Practices Act 1974* (Cth)
PC	Productivity Commission
PSA	Price Surveillance Authority
PTRM	Post Tax Revenue Model
PTS	Principal Transmission System
QGP	Queensland Gas Pipeline
ROE	Return on Equity
SA	South Australia
SWP	South West Pipeline
T&D	Transmission and Distribution
TAR	Tender Approval Request
TFP	Total Factor Productivity
TNSP	Transmission Network Service Provider
TPA	*Trade Practices Act 1974* (Cth)
Tribunal	Australian Competition Tribunal
TXU	Texas Utilities
UK	United Kingdom
URF	Utility Regulators Forum
USA	United States of America
VENCorp	Victorian Energy Networks Corporation
WA	Western Australia
WACC	Weighted Average Cost of Capital
WTS	Western Transmission System

Summary

Outcomes of gas reform

In implementing gas reform, CoAG's objectives were primarily to facilitate the development of a competitive national market for natural gas, prevent abuse of monopoly power and provide rights of access to gas pipelines on conditions that are fair and reasonable for both pipeline companies and users.

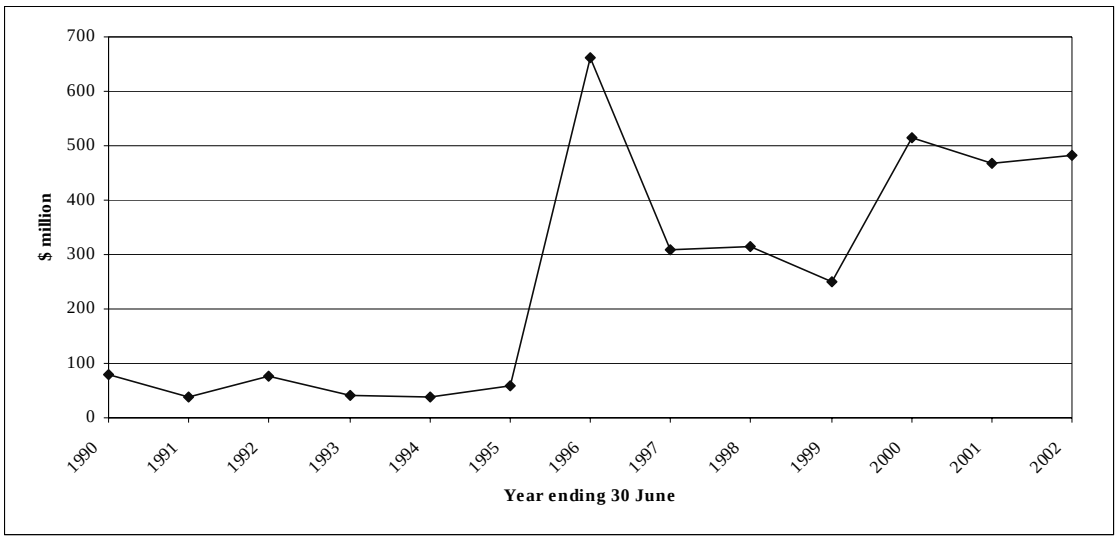
Gas reform since the mid 1990s has supported a significant growth in the industry and should be regarded as a success story. Removal of restrictions on interstate sales of gas, coupled with the introduction of third party access to natural gas transmission and distribution pipelines has encouraged the construction of a number of new pipelines. These pipelines bring new sources of supply to markets, both connecting existing producing basins to new markets and more recently bringing new basins on stream. Gas consumption has grown at an accelerating rate since the mid to late 1990s.

Significant industry growth

In view of the objectives of the Code and the principles it contains for establishing access terms, it is not surprising that investment in the pipeline sector has expanded substantially. It is to be expected that the removal of impediments to fair and reasonable access to the pipeline network would stimulate investment both in the pipeline sector and in dependent markets.

There have been claims that the current regulatory environment is deterring efficient investment. There is no evidence to support this view. In fact, investment in the transmission sector has accelerated since the introduction of the Code. The length of pipelines commissioned and investment measured in terms of capital expenditure has increased substantially.

Figure 1 Capital expenditure on transmission pipelines: 1989-90 to 2001-02



Source: Australian Gas Association, Gas Statistics Australia, various editions.

The AGA lists some 24 pipelines of varying lengths totalling over 5,000 kms that have been constructed since the Code came into operation.[1]

These new pipelines are providing some gas customers with an alternative supplier – but competition in gas supply, particularly in Eastern Australia is still relatively weak. The Parer Review considered that Australia's eastern gas markets can still at best be described as emerging.[2]

Impacts on the pipeline industry

The introduction of the Code has led to a reduction in published pipeline tariffs. Reference tariffs for covered pipelines are typically lower than pre-regulation tariffs. Previously integrated gas companies have been separated into transmission, distribution and retail entities. Most of the original pipeline companies have sold down their interest, establishing trusts or other investment vehicles. This has enabled a number of institutional investors and superannuation funds to take significant holdings.

The ACCC is wary of reading too much into the results of share price trends and asset sales as it is difficult to isolate the cause and effect relationships. Nonetheless, it is informative to note that while the Australian All Ordinaries Index fell by close to 5 percent in the year to 30 June 2003, over the same period regulated gas transmission businesses GasNet and APT have appreciated in excess of 20 per cent. An assessment of APT's share price over the 3 years since it listed reveals that APT has appreciated close to 50 percent while the All Ordinaries Index has marginally declined over the same period.[3] Such share price appreciation is not consistent with the claims that rates of return underlying regulatory decisions have been too low or that regulation is expected to have a 'chilling' effect on efficient investment.

This position is further supported by data from the sales of regulated business in Australia over recent years. Sale prices have consistently exceeded regulatory asset valuations. While there have been a number of reasons put forward to explain the difference in valuations, the implications for investment in regulated industries generally is that they are not being viewed as poor investments.

Progress towards a competitive gas market

The introduction of the Code was intended to promote competition in dependent markets by removing a fundamental obstacle to the emergence of that competition. The ACCC believes that many of the adjustment and implementation costs of establishing Code procedures have been borne but Australia is only just starting to reap the benefits of the emergence of competition in dependent markets. The ongoing costs of the Code should continue to decline over time. The first round of access arrangements was always going to be more contentious and time consuming than subsequent rounds.

There are long lead times for development of new gas fields and pipelines. Nevertheless, new pipelines are now bringing new gas supplies to markets. We are

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1 Australian Gas Association (2003), *Gas Statistics Australia 2002*, p. 54.

2 Parer Review (2002), *Towards a truly national and efficient energy market*, CoAG Energy Market Review Final Report, p. 190.

3 GasNet has not yet been listed for two years.

starting to see the potential for a more competitive gas supply industry – but there is still some way to go.

Evidence on the performance of the gas industry since the introduction of the Code suggests that important steps have been taken towards achieving Governments' objectives.

Given criticisms by some sectors of the gas industry of the current regulatory framework, it is important to keep in mind the rationale for the introduction of the Code. The following sections examine the reasons for access regulation generally, then specifically for gas pipelines. A description of the ACCC's approach to regulation is followed by an assessment of the costs and benefits. This submission concludes by identifying areas for further improvement in the Code's operation.

Regulation of bottleneck facilities

It is widely accepted that vigorous and effective competition normally provides the best means of promoting economic efficiency, a competitive economy and the welfare of consumers. However, in some markets competition may not be possible. This has often been the case in some segments of the electricity and gas sectors.

The terms of reference for the current inquiry specify that the inquiry is to be undertaken within the framework of Part IIIA and to take into account the Government's response to the Review of the National Access Regime. In this context, it is fundamental that the Productivity Commission found, and the Government has accepted, the merits of the National Access Regime (Part IIIA) at this time.

> Given the in principle case for some curbs on the exercise of monopoly power in the provision of essential infrastructure services, the limited experience in Australia with access regimes, and ongoing structural change in a number of infrastructure sectors, abandoning access regulation at this stage would be inappropriate.[4]

General discussion of the economic theory behind regulation has recognised that:

- There may be circumstances where providers of essential facilities possess enduring market power owing to the natural monopoly characteristics of the facility.
- Should owners exercise their market power, a range of adverse effects can arise.
- There is a particular concern where owners of bottleneck facilities also operate in upstream or downstream markets because they may deny potential competitors access to their facilities.
- Concerns about the consequences of monopoly pricing of access, as distinct from denial of access, also underpin regulation.

The case for regulation was recognised by the Productivity Commission on the basis that:

> … in the absence of regulation, denial of access to essential infrastructure services, or monopoly pricing of access, would be more than an isolated occurrence. As well as detracting from the efficient use of the services concerned, such behaviour would also compromise efficient investment in related markets. Moreover, the pursuit of monopoly rents might also

[4] Productivity Commission (2001), *Review of the National Access Regime* (Part IIIA), p. xxxi.

> have adverse consequences for the timing of investment to provide new essential services and to augment existing networks.[5]

Specific regime for gas

In view of the broad acceptance of the need for a National Access Regime it is appropriate to consider whether there is an ongoing rationale for a specific regime for gas pipelines. The need for ongoing regulation of the gas industry was recently examined by the Parer Review which concluded that economic regulation of the gas industry will continue to be required, but left open the form of regulation that should be applied.

> Clearly there are conflicting views regarding the impacts the Gas Code is having. While strong statements have been made by a range of participants regarding the necessity of the Gas Code, the Panel considers that economic regulation will continue to be required for some key infrastructure in the Australian gas market. However, the form of that regulation should remain consistent with the needs of the market as it develops.[6]

In setting up the gas regime, governments recognised that the developing nature of the gas industry warranted a more specific and certain approach than was available under the general access provisions. In part, the rationale for a specific gas regime was driven by the substantial degree of natural monopoly characteristics and market power that are present in gas pipelines connecting major basins and urban distribution systems in Australia. In the absence of a specific regime it was recognised that substantial elements of the industry would be subject to regulation under Part IIIA and so a decision was taken to streamline this process.

In assessing whether a specific regime continues to be appropriate for gas pipelines it is helpful to consider whether the incidence of natural monopoly characteristics and market power continue to be a significant concern. Such an assessment suggests that the incidence of natural monopoly characteristics amongst the mature elements of the gas pipeline industry continues to be substantial. This view is supported by an absence of effective substitutes, high barriers to entry, constrained countervailing power, limited alternative capacity, immature competition and an incentive for pipeline owners to maximise profits rather than throughput. The negative consequences of market power are compounded where vertical relationships are present.

When considering the ongoing rationale for a specific gas regime it is helpful to consider the outcomes that would be likely to arise should the regime be withdrawn and sole reliance placed on the negotiate arbitrate model (NAM) under the general access regime.

The Code has been developed to be a certified State based regime under Part IIIA and to address the specific needs of the gas industry. It establishes a process that is more accessible to multiple access seekers than would operate under the generic provisions of Part IIIA. It also requires access arrangements to meet criteria that are more specific

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5 Productivity Commission (2001), *Part IIIA*, p. 53.

6 Parer Review (2002), p. 192.

to the needs of the industry than the criteria that would apply either to an undertaking or an arbitration determination under the generic provisions of Part IIIA.[7]

The higher level of prescription employed in the Code is appropriate given the expectation that access would be facilitated for an increasing number of upstream and downstream parties. The prescription of access avoids high transaction costs as the number of access seekers increases. A higher level of prescription is also warranted in circumstances where the transmission price is a modest proportion of the final price since access seekers would be unwilling to undertake a costly process in order to eliminate monopoly pricing.

Negotiate arbitrate processes suffer a number of deficiencies in circumstances where the access provider possesses market power. In particular, the NAM introduces incentives for the access provider to delay the process and adopt a 'take it or leave it' approach to negotiation. By contrast the Code provides a framework that facilitates commercial negotiation.

When the Code was being developed consideration was given to the adoption of a NAM. However, for similar reasons to those outlined above the Code developers considered that the reference tariff approach would be more effective than a NAM.

The Code is providing significant certainty and flexibility to support the development of the gas industry and new pipelines. Where regulation is applied to a pipeline, the Code offers a significant degree of flexibility that is yet to be fully realised by the pipeline industry. Since approved access arrangements are now in place for most of the major gas pipelines, commercial negotiations can take place in the context of benchmark terms and conditions including price, facilitating timely access.

A departure from the present framework would add to, and not decrease, regulatory uncertainty. A body of precedent is being established through court and Tribunal decisions and approval of access arrangements which will serve to assist industry and relevant stakeholders in understanding the operation and administration of the Code. While pipeline operators have challenged some aspects of access determinations in the Tribunal, for the most part determinations have been seen as being consistent with the Code. While the Code has been instrumental in progress to date, there remains an important ongoing role for the Code in facilitating future development in the gas industry.

The ACCC's approach to regulation

Once a decision has been made to regulate a particular asset, the Code provides a flexible framework within which the service provider nominates a regulatory approach that best meets its specific circumstances. It is the role of the regulator to assess a service provider's proposed access arrangement against the general principles and objectives set out in the Code. The ACCC encourages a form of regulation that is best

[7] ACCC (2000), *Submission to the Productivity Commission Review of the National Access Regime*, p. 74.

characterised as incentive regulation.[8] Initially, the ACCC approves a framework access arrangement that provides a benchmark for negotiation between the operator and users. Should the regulated entity outperform the benchmark approved by the ACCC by growing the market or operating the pipeline more efficiently, then the entity is permitted to retain the higher earnings.

The building block approach has been found by the ACCC and other regulators to be an appropriate model to assess service providers' proposals. This has been important because efficient prices for gas and electricity businesses were unlikely to exist at the commencement of regulation and there was limited price and benchmarking information. This approach establishes an appropriate benchmark that fully compensates the regulated business for the efficient costs of providing the regulated service.

Guidelines

The ACCC is aware of the importance to investors of a stable and transparent regulatory environment and has worked to minimise uncertainty and maximise the flow of information to investors, service providers and other relevant parties. In this context, the ACCC has released several draft guidelines with the primary function being to minimise uncertainty by educating industry participants and ensuring that the ACCC's intended application of the Code is known. These guidelines include the post-tax revenue model (PTRM), the draft greenfields guideline (DGG) and the regional guideline.

Regulatory settings

In assessing an access arrangement and approving reference tariffs under the Code, there are a range of variables that require judgement to be exercised in order to balance the objectives of the Code and to give appropriate weight to the interests of all parties. The ACCC recognises that investment could be impeded if the regulatory regime places undue financial pressure on asset owners.

Consequently, where there is doubt as to the most appropriate value of such variables, the ACCC has tended to make conservative assessments benefiting service providers to ensure that service providers have access to sufficient resources to continue to operate facilities and undertake new investment. This view is supported by the relative performance of regulated companies against equity markets and the findings of Moody's Investors Service on the regulatory regime in Australia compared to the UK.

> Differences in regulatory philosophy between Australia and the UK mean that Moody's on average rates Australian gas and electricity transmission and distribution (T&D) companies one notch above those of their UK peers, even though both parties may have approximately the same level of debt coverage measures. …
>
> Moody's believes Australian regulators have shown a willingness to let T&D companies earn returns in excess of WACC. …[9]

[8] However, the Code provides flexibility in the type of regulation that a service provider can nominate. For example, the service provider may choose a cost of service model under s.8.3(a).

[9] Moody's Investors Service (August 2003), *Regulatory Differences Justify Higher Rating For Australian Gas And Electricity T&D Companies Over UK Counterparts*, pp. 3-4.

For example, the ACCC has generally computed an equity beta of around one or greater. An equity beta of one implies that the firm has the same level of systematic risk as the market average. However, an equity beta of less than one is more appropriate given the level of market risk for regulated pipelines in Australia. Recent, but limited, empirical evidence prepared by the Allens Consulting Group identified that the most appropriate value for the equity beta might be in the order of 0.7.

The ACCC applies incentive regulation that does not cap the rate of return that a pipeline can achieve. The ACCC establishes a benchmark WACC that the pipeline operator can exceed by achieving efficiency savings or by growing the market. To calculate the benchmark return that is required to compensate investors for bearing the risk associated with investing in a firm's equity the ACCC has consistently accepted the use of the Capital Asset Pricing Model (CAPM). The CAPM has its detractors in the academic and financial community, however, the CAPM is widely accepted and applied across Australian and international capital markets and there is no credible alternative. In addition, there is wide acceptance of the CAPM, the Code uses it as an example of an appropriate model and its use has been consistently proposed by regulated entities.

Evolution of the regulatory approach

In the initial round of access arrangements it has been necessary to undertake comprehensive assessments of pipeline operators' costs and revenue forecasts owing to the absence of information about appropriate prices. However, the ACCC envisages that subsequent assessments for existing pipelines will be increasingly less intensive especially as some key issues were resolved in the initial access arrangements – for example, the value of the initial capital base was determined and is now locked in.

The ACCC and other regulators are making greater use of benchmarks to establish efficient operating costs to enhance the incentives provided. The ACCC recognises that the most appropriate form of regulation will evolve with the industry as it matures and the existing level of flexibility contained within the Code will permit such an approach.

There are a number of issues that may impact on the feasibility of a benchmarking approach in the future including limited productivity data and the ongoing potential for variation in productivity growth between individual companies. Benchmarking shifts the emphasis from a firms own costs, as a result there is greater potential for a firm to earn monopoly profits or alternatively to have insufficient revenue to meet its cost obligations. Either outcome could lead to undesirable outcomes.

Issues specific to greenfields investment

Significant concern has been expressed about the capacity of the Code to recognise issues specific to greenfields investment as opposed to established operations. The ACCC accepts this concern and has explored the issues surrounding new investment in some depth. The ACCC is of the view that specific elements of the Code were drafted with greenfields investment in mind and that the Code is able to support investment in greenfields pipelines. The Draft Greenfields Guideline has been published to provide guidance to prospective developers on implementation of the regulatory regime to new

pipelines. The ACCC has developed strategies to allow service providers to benefit from the upside potential of their investment while still recognising the interests of users.

The 'truncation problem'

A specific example of the concern about the capacity of the Code to accommodate new investment has been the so called 'truncation problem'. In the Productivity Commission's review of Part IIIA it raised the concept of 'regulatory truncation' as a significant risk to new investment. Prior to construction of an infrastructure facility, the developer will assess its likely return on investment against a probability distribution of likely outcomes. A positive probability of low returns may be offset by a possibility of high returns. However, if a high return scenario arises then a regulator may truncate the allowed return. If the developer expects high returns to be capped by a regulator then this will impact on the *ex ante* expected rate of return and may render the project unviable.

The ACCC recognises that if there is a perception that regulators may truncate high return scenarios then socially desirable investment may be delayed or deterred. To address this concern the ACCC has indicated in the greenfields guideline that it is prepared to bind its future discretion by entering into an extended upfront regulatory agreement with pipeline proponents. Such an agreement would offer developers certainty about future regulatory treatment. At the same time, the Code provides sufficient flexibility to accommodate the specific needs of individual pipelines in such an agreement.

In addition to the ACCC's willingness to enter binding upfront agreements, the ACCC is of the view that there are several factors that substantially mitigate the possibility of a 'truncation problem' in the gas pipeline industry. First, pipelines must pass an initial screening process before they are subjected to regulation. Pipelines that do not possess market power are unlikely to be regulated. Moreover, downside risks are truncated for most new pipelines by foundation contracts which guarantee a minimum level of volume and revenue.

Gas regulation is based on the concept of a reference tariff rather than an allowed rate of return, so the regulated entity has the opportunity to earn higher returns if actual volumes exceed forecast volumes. The ACCC regulates on the basis of forecast volumes rather than the capacity of the pipeline. This shifts some volume risk from pipelines to users.

For pipelines that face an uncertain demand situation, a benefit sharing mechanism can be incorporated in the access regime which would share profits (losses) between users and the pipeline developer in high (low) return situations. This would provide certainty about the treatment of high (low) returns in the future. In addition, mechanisms such as adjustments to the depreciation schedule or the capitalisation of losses could be incorporated into the access agreement to offset the potential for losses in the early years of a pipeline.

The costs and benefits of regulatory intervention in gas

Regulation is a second best alternative that is never perfect or costless. However, in the presence of natural monopoly characteristics and market power, the absence of regulation can impose significant costs on the economy. Consequently, it is necessary to undertake an empirical cost benefit analysis to determine whether regulation is generating better outcomes than would be achieved in its absence.

In the context of the Australian gas industry, there is clear evidence to suggest that the current regime is delivering significant net benefits to the industry and the economy. This view is supported by a significant reduction in access prices, examples of third party access to pipeline systems, a high level of investment in the industry, emerging upstream and downstream competition and increased consumption of gas.

The regulatory processes under the Code provide regulators and market participants with the information needed to facilitate market processes and negotiations. Indeed, the concept of a reference tariff provides the market with a considered view as to the appropriate level of tariffs that will balance the interests of all parties.

After five years of application, outcomes under the Code are beginning to achieve a substantial level of stability and predictability. Most coverage issues have now been resolved (or are close to resolution) and most transmission and distribution access arrangements have been settled, with some entering their second iteration. In addition, some aspects of the GasNet and MAPS access arrangements are currently being reviewed in the Tribunal which will add to the volume of jurisprudence surrounding the Code.

As a consequence, investors are now experiencing a high level of comfort with the outcomes that can be expected under the Code. For example, Moody's Investors Service recently stated:

> The ESC and the ACCC's decisions represent evidence – in Moody's opinion – that Australia's current regulatory framework is reasonably stable and predictable. The regulators have applied – with consistency – their methodologies and philosophies in determining lines company revenues …
>
> Importantly, the regulators continue to apply incentive-based pricing methodologies that encourage companies to more efficiently operate their networks. At the same time, the companies are allowed to keep certain portions of their efficiency gains – the excess over the regulators' operating costs, capital expenditure and cost of funds targets.[10]

In this stable environment, the ACCC is moving cautiously to further improve the operation of the regime and to minimise regulatory costs. To this end, the ACCC is investigating greater use of benchmarking approaches to improve incentives and reduce reliance on a firm's own costs. However, in situations where pipeline operators maintain substantial market power alternative approaches to regulation that allow operators significant discretion in setting prices will be problematic.

[10] Moody's Investors Service (July 2003), *Australian/NZ Regulated Distribution and Transmission 2003 Outlook: Stable, but event risk to drive some credit profiles*, p. 3.

Governance

Since the introduction of national competition policy and subsequent industry sector reviews there has been an increasing interest in the design of regulatory institutions in the Australian economy, particularly in relation to access and economic regulators. More recently this interest has manifested itself with various options put forward for reforming the governance arrangements of the energy sector.

Effective institutional arrangements are underpinned by appropriate governance mechanisms that separate regulatory, policy and ownership responsibilities amongst different groups rather than combining any two of these within one entity. In addition regulators should be independent from vested interests and take an economy-wide perspective in discharging their duties. In essence these form the appropriate benchmarks to assess various governance arrangements.

The ACCC's current regulatory responsibilities in utility sectors are complemented by its responsibilities for general competition regulation as an independent economy-wide regulator.

Areas for improvement

In considering the operation of the Code, the ACCC believes that there are some areas for further improvement.

Access arrangement approval process

The Code requires regulators to complete the access arrangement approval process within six months of receiving a proposed access arrangement – although the Code provides for regulators to extend this time period in increments of no more than two months at a time.

For a number of reasons, this six month timeframe has proved difficult for regulators to achieve. There was a large group of initial access arrangements to be approved in the first few years of the Code's operation, which have required some time to work through. The approval process requires a significant amount of public consultation on the various proposals and decisions. In practice, the approval process has been more iterative than envisaged, with additional consultation required each time service providers amend their proposal.

It is important that future access arrangement approvals be made in a more timely manner. The ACCC believes this is achievable with some changes to the current approval process.

The ACCC's experience has been that service providers often submit a number of proposed amendments to access arrangements during the approval process. This has had the effect of significantly delaying the process.

While some flexibility with respect to amendments to a proposed access arrangement prior to the Draft Decision is desirable, this practice can cause significant and unnecessary delay after the Draft Decision. The ACCC believes that to make it possible for the six month approval timeframe envisaged in the Code to be achievable, a change

is required to limit proposed revisions to an access arrangement by service providers to within 28 days of the Draft Decision. This will enable the regulator to proceed to a Final Decision in a timely manner.

Removal of the second final decision could save several months. This step is not essential and is not a common feature of other administrative decision making processes.

The current provision in the Code for limited merits appeal is also creating significant further delays in the process. To expose the entire regulator's determination to the cost and delay associated with a re-determination of the matter is not justified by the benefits of having this type of avenue for appeal. In most cases, the specific matters that are being appealed can be reviewed by a court under an application for judicial review.

Potential for 'switching' services

The ACCC has received complaints from a number of gas industry participants that owners of gas processing facilities have refused to supply switching services. A number of Australia's gas processing facilities have more than one pipeline taking gas from them. This creates the possibility of the processing facility providing basic 'hub' services – effectively switching gas from one pipeline to another.

It is important to distinguish this issue from the more commonly discussed issue of whether third party access to gas processing facilities should be provided. The switching service sought here is merely a reallocation of the gas already being processed – such that more is pumped into one of the pipelines connected to the plant, and less into another. It does not involve any new gas producer having its gas processed in the facility.

Complaints have arisen that processing facilities are not providing this switching service, because the owners are also gas suppliers. This creates an incentive for them not to provide the switching service, to restrict the ability of a potential competitor into a market they supply. This can prevent a gas customer from onselling gas they are required to pay for under a 'take or pay' contract in a situation where they cannot use the contracted gas.

Current remedies such as section 46 of the TPA are not effective. Potentially inefficient physical bypass can be the only effective remedy. At least three bypass pipelines have been built apparently as a result of this problem. There have also been reports of gas sales unable to proceed because the cost of bypass was too high given the value of the proposed transaction.

The ACCC believes that access seekers should be entitled to negotiate access to this 'transportation service' through a gas processing facility with some recourse to regulation in much the same way that they can seek access to pipelines.

Expansions of pipeline capacity

As a pipeline approaches being fully contracted, capacity becomes scarce. In these circumstances, pipeline companies can take advantage of the competitive tension

between existing users and prospective users to increase the price of access in negotiations. In the absence of regulatory intervention, prospective users of that capacity will tend to be forced to pay up to the price of the cost of the next best alternative.

This issue has been addressed by the ACCC requiring that pipelines which may reach a capacity constraint over the regulatory period, have an extensions/expansions policy which specifies that all expansions will be treated as part of the covered pipeline unless the regulator agrees otherwise.

This presumption of coverage enables a prospective user to lodge an access dispute if it is unsatisfied with the outcomes of commercial negotiations over access to prospective expansion capacity.

The ACCC believes it has the legal power to require expansions to be presumed to be covered under the Code, but this has been disputed. An amendment to the Code is required to clarify the Code's ability to address the potential for owners of covered pipelines to use market power to charge excessive prices for access to capacity from expansions.

Competitive tenders under the Code

Obtaining reference tariffs by way of the competitive tendering provisions outlined in the Code is potentially an attractive alternative to proceeding via section 8 of the Code. This is especially the case where governments may wish to facilitate the development of a new pipeline.

The competitive tendering provisions are based on sound theory. However, not all tender processes conducted under the Code have led to the desired result. This is because of three main reasons. First, tenders have been run in situations where demand has been insufficient to provide a commercial return on the costs of constructing the pipeline. Second, some of the organisations running the tender may have imposed restrictive conditions which have reduced the commercial viability of the package. Third, there are some procedural inefficiencies in the competitive tendering provisions in the Code that require adjustment.

Chapter 8 of this submission identifies other areas of the Code where changes can further improve its effectiveness.

Conclusion

The ACCC believes that the Code continues to be fundamental to the achievement of the objectives of gas reform as set out in the various inter-governmental agreements.

The Code has played a significant role in the recent development of Australia's gas industry. While we are starting to see some encouraging signs of greater competition and an emerging national (or at least Eastern) gas market, there is clearly some way to go.

In these circumstances, there remains an important ongoing role for the Code in facilitating future development of Australia's gas industry.

Chapter 1 Outcomes of gas reform

1.1 Objectives of gas reform

Following on from the implementation of the National Competition Policy reforms, the Council of Australian Governments (CoAG) in 1994 agreed to a program of reforms to enable and encourage free and fair trade in natural gas throughout Australia.

Governments committed to removing any legislative restrictions on interstate sales of gas. A national third party access regime for gas pipelines was to be developed to encourage greater competition in markets both upstream and downstream of 'natural monopoly' pipelines (both transmission and distribution).

This led to a further CoAG agreement – the Natural Gas Pipelines Access Agreement – in 1997. This contained a commitment by all jurisdictions to introduce the National Third Party Access Code for Natural Gas Pipeline Systems (the Code) and set out transitional arrangements and some derogations.

CoAG's objective was to establish a framework for third party access to gas pipelines that:

(a) facilitates the development and operation of a national market for natural gas; and
(b) prevents abuse of monopoly power; and
(c) promotes a competitive market for natural gas in which customers may choose suppliers, including producers, retailers and traders; and
(d) provides rights of access to natural gas pipelines on conditions that are fair and reasonable for both service providers and users; and
(e) provides for resolution of disputes.[11]

The following sections address each of these objectives in turn.

1.2 Have these objectives been achieved?

Facilitate the development of a national gas market

Some significant steps have been taken towards the development of a national gas market. Table 1.1 lists the current major gas transmission pipelines in Australia.

A number of new pipelines have been constructed since 1997. The AGA lists some 24 pipelines of varying lengths totalling over 5,000 kms that have been constructed since the Code came into operation.[12] Since 1995, the national transmission network has increased in length from 11,400 km to 20,100 km.

Figure 1.1 below shows the major new pipelines that have been constructed between 1995 and 2002. In addition, the SEAGas pipeline connecting the Otway Basin with the

[11] CoAG Natural Gas Pipelines Access Agreement (7 November 1997) Clause 2.1
[12] Australian Gas Association (2003), *Gas Statistics Australia 2002*, p. 54.

Victorian pipeline system and over to Adelaide is almost completed. This will create a significant loop of pipelines in south east Australia.

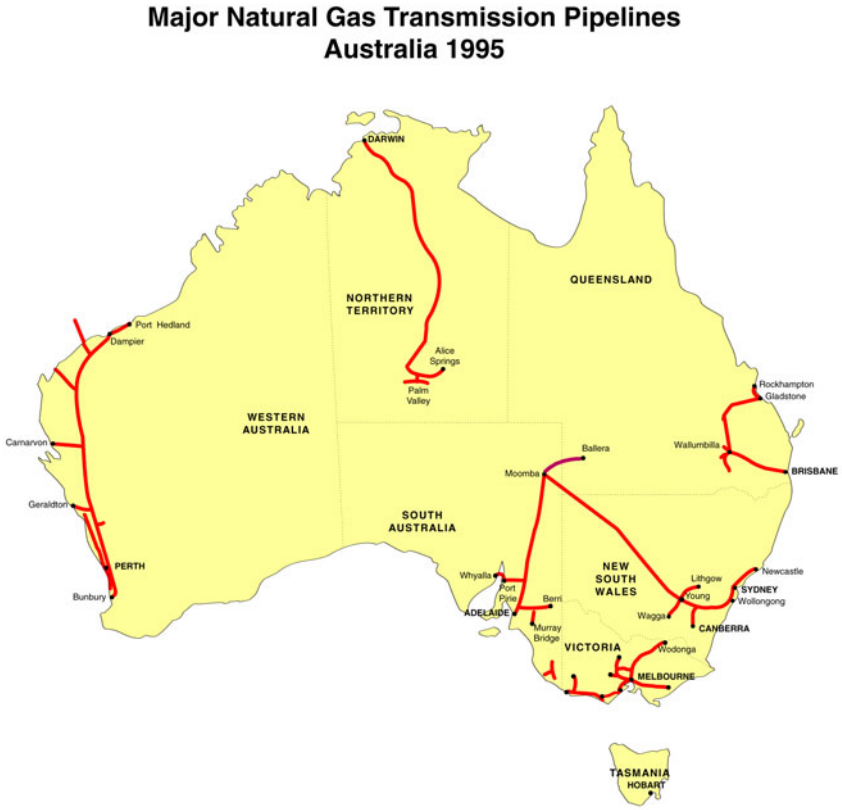
These pipelines bring new sources of supply to markets, both connecting existing producing basins to new markets and more recently bringing new basins on stream.

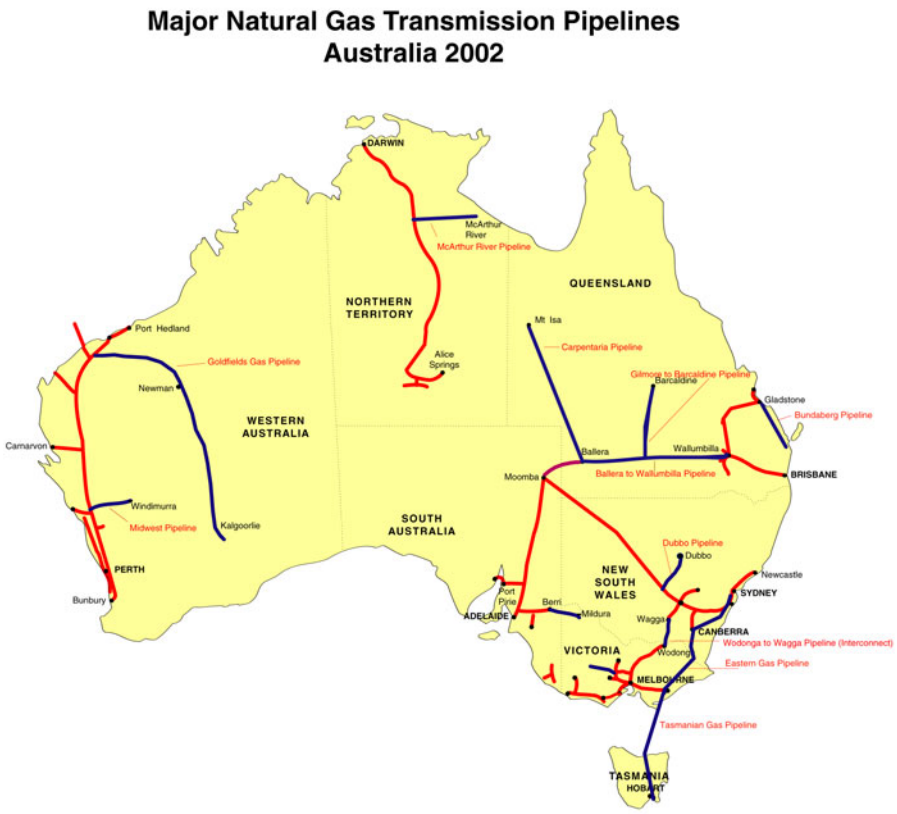
Table 1.1 Current Major Transmission Pipelines

Route	Year[13]	Length (km)	Maximum Capacity (PJ/a)[14]	Diameter (mm)	Regulatory status	Operator/ Owner
Moomba (SA) to Sydney	1976	2013[15]	152	864	Covered[16]	APT
Longford (Vic) to Sydney	2000	795	65	457	Never covered[17]	Duke Energy
Palm Valley to Mataranka/Darwin	1987	1512	20/15	356/324	Covered	APT/ Amadeus Gas Trust
Roma (Wallumbilla) to Brisbane	1969	440	28	273/324/406	Covered	APT
Roma (Wallumbilla) to Gladstone	1989	532	27	324	Covered	Duke Energy
Ballera to Wallumbilla	1996	756	50	406	Covered	Epic Energy
Ballera to Mt Isa	1998	840	30	324	Covered	APT/SWQ Producers
Moomba to Adelaide	1969	781	118	559	Covered	Epic Energy
Victorian Transmission System	1969	1930	211[18]	762/508/168	Covered	GasNet Australia
Dongara to Perth/Pinjarra	1971	415	38	356	Coverage revoked	CMS Gas Transmission of Australia
Dampier to Bunbury	1984	1547	200	660	Covered	Epic Energy
Yarraloola to Newman/Kalgoorlie	1996	1378	35	406/356	Covered[19]	Goldfields Gas Transmission Joint Venture
Longford to Bell Bay, Hobart	2002	576	60	356/203	Never covered	Duke Energy

13 Year originally commissioned.
14 As currently configured.
15 Includes laterals off the mainline.
16 A recommendation by the NCC not to revoke coverage of the MSP is currently being considered by the Commonwealth Minister.
17 Based on an NCC recommendation, the Minister decided that the EGP should be covered. This decision was set aside on appeal to the Tribunal.
18 This is an estimate of annual gas transportation.
19 An application for revocation of coverage of the Goldfields pipeline is currently being considered by the NCC.

Figure 1.1 Comparison of gas transmission pipelines: 1995-2002





Investment and market development: what is the evidence?

For some time now, the pipeline industry has been claiming that the current regulatory environment is deterring efficient investment. For example, in a media release on 28 October 2001, APIA stated:

> The current regulatory quagmire is suffocating new pipeline development and requires urgent policy attention by governments.[20]

In considering this issue in the context of the Part IIIA Review, the Productivity Commission was minded to accept the view that access regulation was deterring investment.

> Nevertheless, in the Commission's view, the concerns about the potential for access regulation to deter investment appear to be well-founded.[21]

However, in the context of the gas transport sector the weight of evidence is strongly against the claims made by the pipeline industry.

The ACCC believes there is no evidence that efficient investment in the transmission sector has been deterred following the introduction of the Code. Rather, investment

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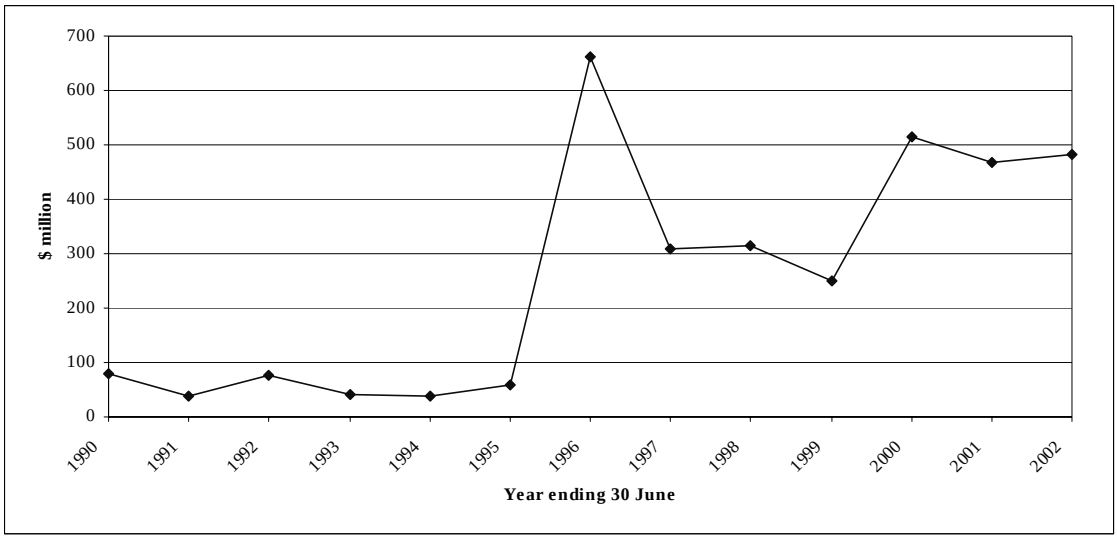
[20] Australian Pipeline Industry Association 28 October 2001, *Media release: urgent call for national leadership in Australia's gas infrastructure development*.

[21] Productivity Commission (2001), *Review of the National Access Regime (Part IIIA)*, p. 67.

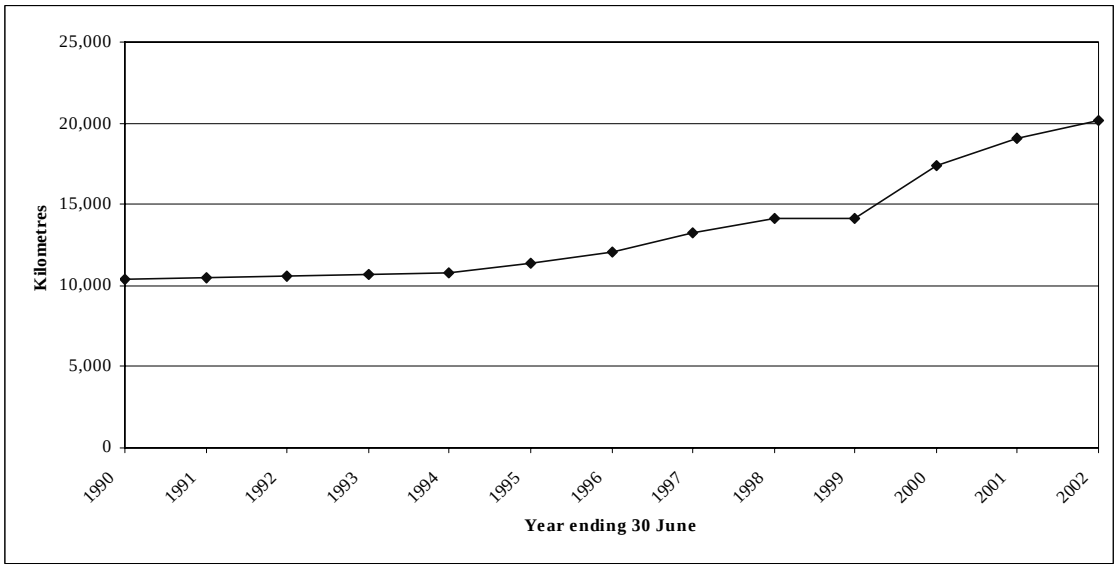
measured in terms of capital expenditure and length of pipelines commissioned has accelerated substantially as illustrated below.

Figure 1.2 Transmission Pipeline Capital Expenditure 1990-2002



Source: Australian Gas Association, Gas Statistics Australia, various editions.

Figure 1.3 Length of transmission pipelines: 1990-2002



Source: Australian Gas Association, Gas Statistics Australia, various editions.

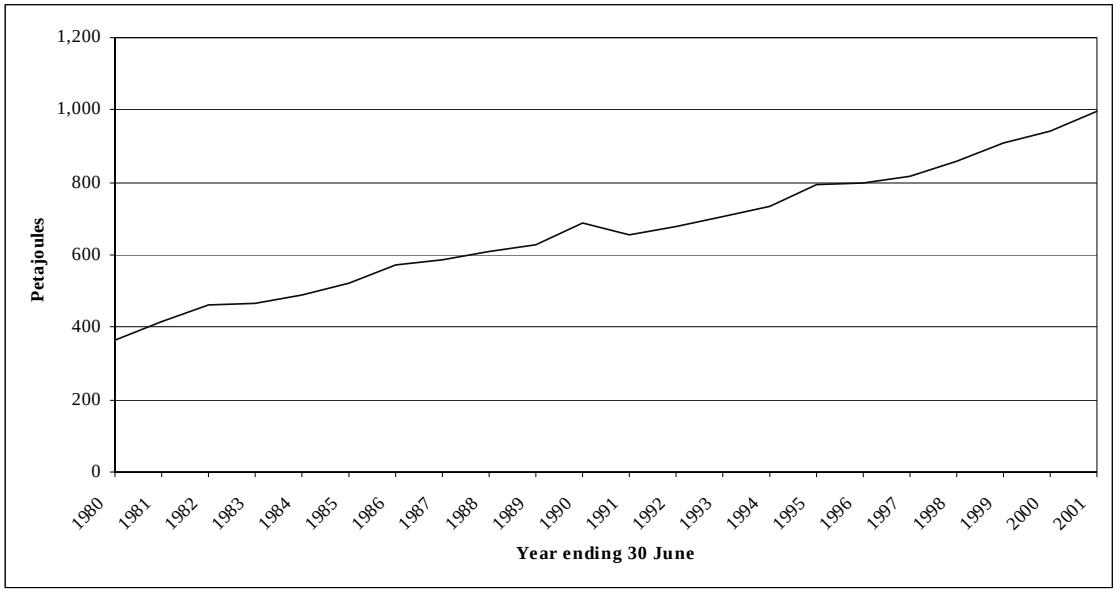
This view is supported by BHP Petroleum in its submission to the Part IIIA review:

> Thus the policy environment for new pipelines (transmission and distribution) investment has been known for some 3-4 years. BHP has seen no evidence that investment in pipelines is being deterred by the Code …
>
> The fact that access has had no negative impact on pipeline investment in Australia should be no surprise. This is consistent with experience in the USA and in Canada, where pipeline investment has thrived notwithstanding in a more rigorous and onerous regulatory environment.[22]

[22] BHP Petroleum (14 February 2001), *Submission to Productivity Commission Part IIIA review*, p. 62.

Another positive indicator of the effects of gas reform and the introduction of the regulatory access regime is that gas consumption has grown at an accelerating rate since the mid to late 1990s. Between 1990 and 1995 gas consumption grew at an average annual rate of 3 per cent. Since 1995, gas consumption has grown at an average annual rate of around 4 per cent.

Figure 1.4 Gas Consumption in Australia 1980-2001



Source: Australian Gas Association, Gas Statistics Australia, various editions.

This issue of investment incentives was considered in some detail by the Parer Review. The Review was unable to identify any specific instances where the regulatory regime had been solely responsible for deterring the development of new pipelines.

> The Panel wrote to the APIA, asking for evidence of prospective pipelines not proceeding solely because of the operation and application of the Gas Code. In reply, the APIA did not identify any such pipelines and acknowledged that there are a suite of barriers to new transmission pipeline development.[23]

Further, the Review went on to note that:

> Significant additions to the nation's pipeline infrastructure over the last ten years have enhanced the competitiveness of the natural gas market considerably.[24]

and

> It is worth noting, however, that this investment has been made with the Gas Code in operation. The APPEA '… believes that pipeline access regulation has not been hindering investment in economic pipelines, which has been significant in recent years.'[25]

In fact, rather than hindering pipeline development, there is evidence that the Code is encouraging it:

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23 Parer Review (2002), *Towards a truly national and efficient energy market, CoAG Energy Market Review Final Report*, p. 191.

24 Parer Review (2002), p. 192.

25 Parer Review (2002), p. 193.

> Indeed, there is some new pipeline investment that is directly attributable to the introduction of access. BHP developed the Eastern Gas Pipeline project on the basis that access would be available to the existing NSW gas distribution system. The pipeline would not have been built without access. Thus the Eastern Gas Pipeline is a $450m project that has been directly facilitated by the Code.[26]

Confidence in the regulatory regime

The Code has been in operation for almost six years. Most coverage issues have now been resolved[27] (or are close to resolution) and most of the initial transmission and distribution access arrangements have been settled, with some entering their second iteration. Further, the GasNet and MAPS access arrangements are currently being reviewed in the Tribunal which will provide additional jurisprudence on regulatory decisions and processes under the Code.

Similarly, investors are now experiencing a high level of confidence with respect to the outcomes that can be expected under the Code.

This confidence in the regulatory regime is reflected in comments by observers of the regime. Moody's Investors Service is of the opinion that:

> Tariff decisions in 2002 for Victorian gas distributors, gas and electricity transmission companies as well as South Australian electricity transmission firms demonstrate that overall regulatory philosophies are fairly stable and predictable, at least in Australia. Signs are that this will remain so over the medium term, and that the tariff resets scheduled in 2006 for Victorian and South Australian electricity distributors will reflect this situation. In fact, we anticipate regulatory stability, at least until 2010.[28]

Confidence in the regulatory regime, or greater certainty regarding outcomes from it, can be an important factor in encouraging new investment. Indeed new pipelines are being developed without regulatory oversight including SEAGas and the Tasmanian gas pipeline.

Prevent abuse of monopoly power

Two key elements of the Code that seek to prevent abuse of monopoly power by pipeline companies are the approval of reference tariffs and the ring fencing arrangements.

Reference tariffs

The Access Arrangement approval process seeks to address pipeline market power by addressing the information asymmetry (release of access arrangement information) and in determining a fair and reasonable benchmark tariff and associated terms and conditions. This provides access seekers with a basis for commercial negotiation, and the backstop of being able to rely on dispute resolution processes and finally binding

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26 BHP Petroleum (14 February 2001), *Submission to Productivity Commission Part IIIA review*, p. 62.

27 The NCC's MSP revocation recommendation is currently before the Minister.

28 Moody's Investors Service (July 2003), *Australian/NZ Regulated Distribution and Transmission 2003 Outlook: Stable, but event risk to drive some credit profiles*, p. 1.

arbitration in the event that commercial negotiation fails to deliver a fair and reasonable outcome.

The ACCC believes that the Code is effectively addressing the potential for gas pipelines to abuse monopoly power through the access arrangement and reference tariff approval process. The introduction of the Code and setting of reference tariffs has led to a reduction in published pipeline tariffs. Reference tariffs for covered pipelines are typically lower than pre-regulation tariffs. Table 1.2 shows tariffs sought by service providers compared to tariffs granted by the ACCC.

Table 1.2 Tariffs sought by service providers and those granted by the ACCC

Pipeline	Tariff Sought ($/GJ)	Tariff Granted ($/GJ)
Amadeus Basin to Darwin Pipeline	3.46/GJ	2.88/GJ
Central West Pipeline	2.17/GJ	2.17/GJ
Moomba to Adelaide Pipeline	0.43/GJ	0.39/GJ[29]
Moomba to Sydney Pipeline	0.71/GJ/0.66/GJ[30]	0.43/GJ[31]
Victorian Principal Transmission System including Western Transmission System (First AA)	Average 0.3439/GJ	Average 0.2985/GJ
Victorian Principal Transmission System including WTS, SWP and interconnect (Second AA)	Average 0.4344/GJ	Average 0.3626/GJ[32]

One issue where the ACCC has received some complaints is with respect to attempts to 'switch' gas from one pipeline to another through a gas processing facility. This issue is discussed in detail in Chapter 8 of this Submission.

Ring fencing arrangements

The Code requires pipeline companies to be separate legal entities – not holding interests in any upstream or downstream market participants. Further, any contracts with related parties must be approved by the ACCC before they can come into effect. These measures are designed to reduce the incentives for anticompetitive behaviour by pipeline companies.

The ACCC has not received any complaints from users that the ring fencing arrangements are not working.

Promote a competitive market for natural gas

A key element of this objective was to enable gas customers to have a choice of producers, retailers and traders. The construction of new pipelines bringing alternative supplies to most markets described above has been a critical step towards achieving this objective. For example, reports indicate that the Queensland Government received eighteen bids from ten different bidders to supply gas to the Townsville power station.

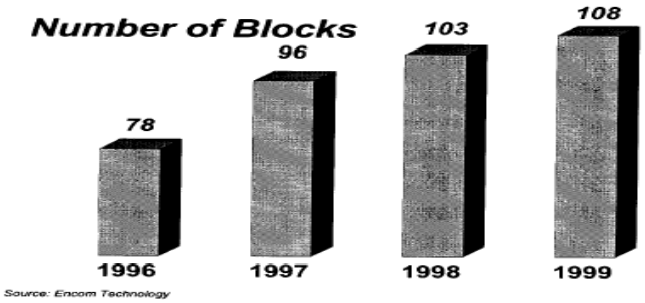
29 Estimate from Final Approval
30 Revised access arrangement
31 This is the tariff proposed in the Draft Decision – this access arrangement has yet to be finalised.
32 This is the tariff contained in the ACCC's Final Approval, but is currently subject to appeal.

Governments have also gradually made their gas markets contestable, granting retail licences to new entrants and establishing new market operating rules to facilitate customer switching between retailers. New retailers can have confidence that they may obtain access to customers via distribution networks on reasonable terms and conditions. These are the first steps in developing a competitive market.

Further encouraging signs are gas storage facilities being established. Also Duke Energy is starting to offer some gas financial products in a number of States, such as price hedging, from its newly established 'hub' in Victoria.

Though access regulation has been perceived to have the potential to deter investment, the evidence is that new investment has taken place and had the effect of increasing competition in both upstream and downstream markets. BHP in its submission to the Productivity Commission review of Part IIIA commenting on upstream development stated:

> The upstream development process involves a number of sequential steps – acreage acquisition, seismic interpretation, exploration and appraisal drilling, marketing and development- with a cycle time of typically 5 years. The Gas Pipeline Access Code was adopted by CoAG in November 1997, and progressively legislated over the past three years. It is therefore premature to draw any firm conclusions on the success or otherwise of regulating access in facilitating upstream competition. However, there are some leading indicators of enhanced activity. The diagram below shows the number of upstream concessions held in Victoria (onshore and offshore) by companies other than BHP or Exxon Mobil. This shows a significant increase over a period when oil prices were flat or declining.
>
> **Upstream Concessions Victoria 1996-1999 (Excluding Esso and BHP)**



> There has also been increased activity on a number of potential gas field developments in or adjunct to Victoria, including Kipper, Patricia/Baleen, Sale and Yolla. It is too early for policy makers to declare success in this area, but the early signs are encouraging.[33]

Provide access on terms that are fair and reasonable

The Code requires the ACCC to approve reference tariffs for covered pipelines in a manner that takes account of the legitimate business interests of service providers and the interests of users. The manner in which the ACCC assesses proposed reference tariffs is discussed in detail in Chapter 4.

[33] BHP Petroleum (14 February 2001), *Submission to Productivity Commission Part IIIA review*, p. 61.

Previously integrated gas companies have been separated into transmission, distribution and retail entities. Most of the original pipeline companies have sold down their interest, establishing trusts or other investment vehicles. This has enabled a number of institutional investors and superannuation funds to take significant holdings.

The ACCC is wary of reading too much into the results of share price trends and asset sales as it is difficult to isolate the cause and effect relationship. Nonetheless, it is informative to note that while the Australian All Ordinaries Index fell by close to 5 percent in the year to 30 June 2003, over the same period regulated gas transmission businesses GasNet and the Australian Pipeline Trust (APT) have appreciated well in excess of 20 percent. An assessment of APT's share price over the 3 years since it listed reveals that APT has appreciated close to 50 percent while the All Ordinaries Index has marginally declined over the same period.[34] Such share price appreciation is not consistent with the claims that rates of return underlying regulatory decisions have been too low or that regulation is having a 'chilling' effect on efficient investment.

This position is further supported by data from the sales of regulated business in Australia over recent years. Sale prices have consistently exceeded regulatory asset valuations. While there have been a number of reasons put forward to explain the difference in valuations, the implications for investment in regulated industries generally is that they are not being viewed as poor investments.

The then acting WA Premier Eric Ripper in an interview with the Australian Financial Review with reference to Epic Energy supported the regulatory regime that is in place and recognised that individual pipeline companies' problems were not a reflection on the regulatory regime:

> If Epic believes that they don't have the financial capacity to expand the pipeline they should be thinking of whether someone else has the capacity. This is a very significant part of the states infrastructure and they have obligations to the West Australian community. Investments in the expansion of the pipeline under the current regulators decision would be economic, were it not for Epic's own problems.[35]

In a report to investors, international financial analysts Moody's gave a positive assessment of the Australian energy regulatory environment. It compared recent regulatory decisions in Australia with those of the United Kingdom – which has a very similar regulatory regime and approach. Moody's concluded:

> Differences in regulatory philosophy between Australia and the UK mean that Moody's on average rates Australian gas and electricity transmission and distribution (T&D) companies one notch above those of their UK peers, even though both parties may have approximately the same level of debt coverage measures. …
>
> Moody's believes Australian regulators have shown a willingness to let T&D companies earn returns in excess of WACC. …
>
> Furthermore, the use of more aggressive capital structures – relative to the modelled capital structure assumed by regulators – is widespread. This means T&D companies can operate at a cost of capital below regulatory WACC.

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34 GasNet has not yet been listed for two years.

35 AFR, (7 August 2003), *Ripper backs pipeline sale*, p. 17.

> So far, Australia's regulators have allowed this practice to continue and show no sign of matching regulatory assumptions with market reality.[36]

The ACCC recognises that investment could be impeded if the regulatory regime places undue financial pressure on asset owners. Consequently, where there is doubt as to the most appropriate value of such variables, the ACCC has tended to make a conservative assessment to the benefit of service providers to ensure that the service provider has access to sufficient resources to continue to operate the facility and undertake new investment.

Provide for resolution of disputes

The Code contains a dispute resolution mechanism. Essentially it provides for arbitration of disputes should commercial negotiation be unable to deliver an outcome acceptable to both parties.

The ACCC is yet to have a dispute under the Code brought to it for resolution.

Conclusions on reform outcomes

As has been demonstrated, the gas industry has grown significantly since the mid 1990s and gas reform should be regarded as a success story.

The recent Parer Review found that:

> The reform of Australia's energy markets has brought significant benefits to date. Australia can point to:
> - Electricity and gas prices that are now competitive with other OECD member countries.
> - Market signals working effectively to induce appropriate new generation investment.
> - New gas resources being discovered and exploited.
> - Significant additional pipelines constructed between and within jurisdictions (both regulated and not).
> - Substantial improvement in the participation of consumers in the energy market through choice of retailer. [37]

The ongoing costs of the Code should continue to decline over time. The first round of access arrangements was always going to be more contentious and time consuming than subsequent rounds. This is significantly due to the once-off requirement to establish an initial capital base for regulatory purposes and it is also due to the lack of precedents or jurisprudence in this field within Australia.

The introduction of the Code was intended to promote competition in dependent markets by removing a fundamental obstacle to the emergence of that competition. The ACCC believes that many of the adjustment and implementation costs of gas reform have been borne but Australia is only just starting to reap the benefits of the emergence of competition in dependent markets. There are long lead times for development of new gas fields and pipelines. Nevertheless, new pipelines are now bringing new gas supplies

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36 Moody's Investors Service (August 2003), *Regulatory Differences Justify Higher Rating For Australian Gas And Electricity T&D Companies Over UK Counterparts*, pp. 3-4.

37 Parer Review (2002), p. 63.

to markets. We are starting to see the potential for a more competitive gas supply industry – but there is still some way to go.

These new pipelines are providing some gas customers with an alternative supplier – but competition in gas supply, particularly in Eastern Australia is still relatively weak. The Parer Review considered that Australia's eastern gas markets can still at best be described as emerging.[38]

Evidence on the performance of the gas industry since the introduction of the Code suggests that important steps have been taken towards achieving Governments' objectives.

However, given criticisms by some sectors of the gas industry of the current regulatory framework, it is important to keep in mind the rationale for the introduction of the Code. The following chapters of this submission examine the reasons for access regulation generally, then specifically for gas pipelines. A description of the ACCC's approach to regulation is followed by an assessment of the costs and benefits. This submission concludes by identifying areas for further improvement in the Code's operation.

[38] Parer Review (2002), p. 190.

Chapter 2 Regulation of bottleneck facilities

The terms of reference for the current inquiry specify that the inquiry is to be undertaken within the framework of Part IIIA and to take into account the Government's response to the Review of the National Access Regime. In this context, it is fundamental that the Productivity Commission found, and the Government has accepted, the merits of the National Access Regime at this time.

> Given the in principle case for some curbs on the exercise of monopoly power in the provision of essential infrastructure services, the limited experience in Australia with access regimes, and ongoing structural change in a number of infrastructure sectors, abandoning access regulation at this stage would be inappropriate.[39]

2.1 Economic theory behind regulation

It is widely accepted that vigorous and effective competition normally provides the best means of promoting economic efficiency, a competitive economy and the welfare of consumers. Competition is a process which centres on the active efforts of firms to keep ahead by reducing costs, developing new products and enhancing the quality of their services. It is a process which forces businesses to offer 'more for less' by improving quality and/or lowering prices. At a broader level competition also helps to ensure that the community's scarce resources are used in the most valuable way now and through time.[40]

However, in some markets competition may not be possible. This has often been the case in some segments of the electricity and gas sectors. Transmission and distribution service providers often face limited direct competition because of significant economies of scale and high barriers to entry. That is, they exhibit natural monopoly characteristics. These businesses also have the ability to exert market power in upstream and/or downstream markets.[41]

Where competition is ineffective, markets do not deliver optimal outcomes and regulatory intervention may be justified. However, the presence of monopoly power alone is not sufficient to justify regulation, rather it is necessary to consider at least two threshold questions:

> In assessing the need for access (or alternative) regulation, the extent of monopoly power in the delivery of essential infrastructure services, and the significance of the problems this creates, are clearly threshold considerations.[42]

An essential element of a consideration of the need for regulation is a comprehensive cost benefit analysis where the situation without regulatory intervention is weighed against the outcomes that could be expected if intervention is undertaken.

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39 Productivity Commission (2001), *Review of the National Access Regime*, Report No. 17, 28 September 2001, (*Part IIIA)*, p. xxxi.

40 ACCC (May 2002), submission to the Parer Review, p. 25.

41 ACCC (May 2002), submission to the Parer Review, p. 25.

42 Productivity Commission (2001), *Part IIIA*, p. 50.

> Even if it were accepted that market power is present and causes large economic costs, this is not sufficient grounds for government intervention. The appropriate test of any intervention is how outcomes compare with alternative interventions, including the option of doing nothing.[43]

2.2 The case for general access regulation

In accepting the case for general access regulation in its review of the National Access Regime, the Productivity Commission concluded that denial of access and/or monopoly pricing would not be insignificant events in the Australian economy.

> … in the absence of regulation, denial of access to essential infrastructure services, or monopoly pricing of access, would be more than an isolated occurrence. As well as detracting from the efficient use of the services concerned, such behaviour would also compromise efficient investment in related markets. Moreover, the pursuit of monopoly rents might also have adverse consequences for the timing of investment to provide new essential services and to augment existing networks.[44]

Further, at this stage the benefits of maintaining a national access regime are likely to outweigh the costs.

> … abandoning access regulation at this stage would be inappropriate. In its [the Productivity Commission's] view, the natural monopoly characteristics of a number of essential infrastructure services mean that an explicit mechanism for facilitating efficient third party access is likely to be desirable. … The Commission further considers that the current approach of the Part IIIA regime operating in tandem with industry access regimes has significant advantages. Industry regimes provide the flexibility to tailor access arrangements to the characteristics of particular infrastructure sectors.[45]

An outline of the key findings on the case for regulation in the Review of the National Access Regime is set out in Box 2.1. In the context of the current inquiry, the key findings included:

- There may be circumstances where providers of essential facilities possess enduring market power owing to the natural monopoly characteristics of the facility and conditions in the market.
- Should the owner exercise its market power, a range of adverse effects can arise.
- There is a particular concern where owners of bottleneck facilities also operate in upstream or downstream markets as they may deny potential competitors access to their facilities.
- Concerns about the consequences of monopoly pricing of access, as distinct from denial of access, also underpin regulation.

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43 Productivity Commission (2001), *Telecommunications Competition Regulation*, Report No. 16, Ausinfo, Canberra, p. 21.

44 Productivity Commission (2001), *Part IIIA*, p. 53.

45 Productivity Commission (2001), *Part IIIA*, p. xx.

Box 2.1 Key conclusions in respect of economic theory behind regulation in the Productivity Commission's review of the National Access Regime[46]

- In most circumstances, competition between suppliers of goods and services will result in lower prices, a wider range of products, or better service for consumers (p. 38).
- Transitory market power is a feature of virtually all markets. However, the competitive responses of rival firms will typically see that market power eroded (p. 40).
- However, demand and supply conditions for essential infrastructure services are such that providers may sometimes have enduring market power. In most analyses, such market power is seen to stem from natural monopoly (p. 40).
- The classic text book natural monopoly refers to a situation where one provider is able to meet total market demand at a lower unit cost than could two or more providers (p. 40).
- Natural monopoly may not be sustainable over time. Changes in demand, costs or new technology may make a monopolised market contestable (p. 43).
- Market power may not necessarily arise in all circumstances where there is a sustainable natural monopoly technology. It may be the case that there are effective substitutes for the services provided by the technology. Alternatively, competition in downstream markets may restrain the exercise of market power in upstream markets or customers may be able to exercise countervailing power (p. 43). Thus, it may be more appropriate to focus on the concept of bottleneck infrastructure rather than natural monopoly (p. 45).
- However, competition may not be feasible in some aspects of infrastructure provision and the shared use of some bottleneck infrastructure may be necessary to facilitate competition in markets that rely on this infrastructure (p. 39).
- The denial of access to competitors in related markets is likely to have adverse efficiency effects. So too will monopoly pricing of services, even if access is provided to all those seeking it. Such behaviour is also likely to affect income distribution (p. 45). The scope of adverse effects may include higher prices, suboptimal usage, income transfers (p. 47), reduced competitiveness in downstream markets, reduced quality and reliability, distortions in investment decisions (p. 48) and lack of innovation (p. 49).
- Traditionally, government monopolies have dominated the provision of infrastructure services. Significant reform has been undertaken over the past two decades which has resulted in vertical separation, removal of legislative restrictions, privatisation, competition in contestable parts of service delivery and the entry of new players (p. 38).
- Access regulation aims to promote competition in markets that use the services of bottleneck or essential infrastructure facilities. There is a particular concern where owners of bottleneck facilities also operate in upstream or downstream markets as they may deny potential competitors access to their facilities (p. 39).
- Concerns about monopoly pricing of access, as distinct from denial of access, also underpin regulation. In effect, the presumption is that the exercise of monopoly power by owners of essential facilities will be to the detriment of providers in related markets and ultimately to users of the final services (pp. 39, 40).
- The key access policy issues will relate mainly to any adverse consequences of ongoing supply of bottleneck services by a single entity. But socially wasteful duplication of essential infrastructure may also pose some concerns (p. 42).

[46] See Productivity Commission (2001), *Part IIIA*, pp. 38-50.

Chapter 3 The case for a specific gas regime

This Chapter explores whether there is an ongoing rationale for a specific regime for gas pipelines in view of the acceptance of the National Access Regime. The need for ongoing regulation of the gas industry was recently examined by the Parer Review which concluded that economic regulation of the gas industry will continue to be required, but left open the form of regulation that should be applied.

> Clearly there are conflicting views regarding the impacts the Gas Code is having. While strong statements have been made by a range of participants regarding the necessity of the Gas Code, the Panel considers that economic regulation will continue to be required for some key infrastructure in the Australian gas market. However, the form of that regulation should remain consistent with the needs of the market as it develops.[47]

In examining the ongoing need for a specific gas regime, the ACCC wishes to highlight four key issues:

- The initial rationale for the gas regime;
- The extent of natural monopoly characteristics and market power in gas pipelines;
- The efficacy of Part IIIA; and
- The place of price monitoring.

3.1 Background to the Code

Historical considerations

In setting up the gas regime, governments recognised that the developing nature of the gas industry warranted a more specific approach than was available under the general access provisions.

Concerns about the extent of natural monopoly characteristics in the gas industry had been recognised for many years. Traditionally, State governments have played a significant role in the development of the gas industry in Australia. This role has included regulation of the industry, development and ownership of pipelines and the establishment of foundation contracts. In part, this involvement was motivated by the natural monopoly characteristics of the industry and the need to restrain potentially adverse behaviour.

Since the early 1990s State governments have progressively reduced their active involvement in the industry through structural separation, privatisation and corporatisation as part of the broader micro-economic reform agenda. Following the Hilmer Review, governments moved to introduce the National Third Party Access Code for Natural Gas Pipeline Systems to achieve free and fair trade in natural gas and to foster competition in the delivery of gas.[48]

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47 Parer Review (2002), p. 192.

48 CoAG 1997, *Communique of meeting*, 7 June 1997.

Market development

Fostering the development of the natural gas market was a key consideration in establishing the Code and this is reflected in its objectives. There is strong evidence that significant progress has been made in achieving this objective, but substantial development is still required. For example, the Parer Review found that:

> The recent gas reforms have been effective. By facilitating access to pipelines, and removing the previous restrictions on interstate trade in gas, new pipelines have and are being built, new fields have been discovered, and some initial upstream gas competition has been introduced.
>
> Australia's gas market, however, is still immature. It remains an emerging market. There is insufficient upstream competition, and it is characterised by long term bilateral contracts with virtually no ability to adjust positions as circumstances change.
>
> There is clear benefit in facilitating the move to a more mature gas commodity market with many players and an active short term market. This will promote the more widespread use of gas, and more efficiency, through the opportunity for participants to involve themselves in the market in a wider variety of ways.[49]

and

> These are all encouraging signs of a market that is developing. In this context, the Panel believes that while there have been strong concerns raised regarding the current arrangements in gas, the market is developing and becoming more competitive, dynamic and efficient.
>
> Nevertheless, Australia's eastern gas markets can still at best be described as emerging. While these recent developments are encouraging, Australia's gas markets remain immature — particularly when compared with the gas markets in the United Kingdom or United States of America. The degree of supply competition in Australia's eastern markets is still weak — particularly compared to Western Australia. This is reflected in lower gas prices in WA.
>
> Some significant barriers to a truly competitive natural gas market remain. The limited competition arising from the small number of basins supplying eastern gas markets is further restricted by joint marketing of gas from within those basins. In addition, the high level of upstream ownership concentration across basins is a concern. Another barrier to a competitive market is the relatively small size of the Australian economy.[50]

While the Code has been instrumental in progress to date, there remains an important ongoing role for the Code in facilitating future development in the gas industry.

Quarantining the incidence of regulation

The regulatory process for gas pipelines is a two step process. First, an assessment is made of the extent of natural monopoly characteristics and the benefits that would arise if the enduring market power were alleviated. This is the coverage process and it determines the need for regulation to be applied.[51]

Second, once the need for regulation of a particular asset has been determined then an access arrangement is required. The access agreement provides a basis for negotiation

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49 Parer Review (2002), p. 35.

50 Parer Review (2002), p. 190.

51 Initially, a large number of pipelines were listed in Schedule A to the Code and were deemed to be covered. Subsequently, a number of pipelines have had coverage revoked following applications to the NCC.

that balances the interests of all parties including the public interest in preventing the abuse of market power.

The coverage criteria as applied by the NCC and Tribunal first ask whether the facility exhibits natural monopoly characteristics. If this question is answered in the affirmative then the assessment turns to whether the pipeline is able to exercise market power in a dependent market and investigates the benefits that would accrue if the pipeline was constrained from exercising its market power.

> 5.4 The Council presents its analysis of the coverage criteria in the following order: criterion (b); criterion (a); criterion (c); criterion (d).
>
> 5.5 The Council considers it logical to begin with criterion (b), as it focuses on the service to which access is sought and asks whether the pipeline providing that service is a natural monopoly.
>
> 5.6 Criterion (a) is wider in scope as it requires consideration of industry structure and whether the service provider is able to exercise market power in relation to dependent markets. Criterion (a) also raises the issue of access, testing whether a pipeline is a "bottleneck" facility. While natural monopoly characteristics is a necessary pre-condition for a pipeline to be a "bottleneck," it also requires that the pipeline occupies a strategic position in a supply chain.
>
> 5.7 The Council's approach in assessing criterion (b) ahead of criterion (a) is consistent with the Tribunal's approach in the Duke EGP decision.[52]

Evidence on the application of the coverage test to date suggests that it has operated as an effective filter for determining the need for regulatory intervention. For example, the NCC's submission to the Parer Review stated:

> Experience to date shows that the coverage criteria in section 1.9 of the National Gas Code have confined access regulation to fewer gas pipelines than originally envisaged by governments. Furthermore, the current wording is subject to significant authority through the Australian Competition Tribunal's (the Tribunal) decisions in the Sydney Airports case and the Duke Eastern Gas Pipeline case.[53]

The NCC also stated:

> The Council agrees with the Issues Paper's statement that the Tribunal's decisions in the EGP and Sydney Airports cases have clarified that coverage is only available in relation to the services of natural monopoly infrastructure where that natural monopoly has sufficient market power in a dependent market to affect competition. In the case of natural gas pipelines, the focus of a coverage/revocation process will often be on the question of whether a particular pipeline has sufficient market power to potentially hinder competition in a dependent market. The Council's experience has been that most natural gas pipelines in Australia are natural monopolies, though as natural monopoly is a dynamic concept, this may not always be the case.[54]

In conclusion the NCC stated:

> The coverage criteria in section 1.9 of the National Gas Code do outline an appropriate test for identification of the natural gas pipelines that should be regulated. The coverage and revocation

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52 NCC (2002), *MSP decision*, p. 86.
53 NCC (2002), *Submission to Parer Review*, p. 58.
54 NCC (2002), *Submission to Parer Review*, p. 59.

> processes provide the opportunity for interested parties to test whether regulation is appropriate in the case of a particular pipeline.[55]

3.2 Natural monopoly and market power

In part, the rationale for a specific gas regime was driven by the substantial degree of natural monopoly characteristics and market power that are present in gas pipelines connecting major basins and urban distribution systems in Australia. In the absence of a specific regime it was recognised that substantial elements of the industry would be subject to regulation under Part IIIA and so a decision was taken to streamline this process.

In assessing whether a specific regime continues to be appropriate for gas pipelines it is helpful to consider whether the incidence of natural monopoly characteristics and market power continue to be significant concerns. In undertaking this assessment, the following issues are of relevance.

Market definition

There is an argument that the gas supply chain (including the pipeline sector) is constrained from exercising market power owing to competition from other energy sources. This argument raises the prospect that the relevant product market may include other energy sources rather than being a gas specific market.

However, in the past the Tribunal has consistently found that gas prices are not effectively constrained by alternative energy sources and has found the product market to be a gas specific market. In its decision on the MSP, the NCC cites two instances where the Tribunal has found that the relevant market is a natural gas market.[56] First, in the AGL Cooper Basin supply arrangements decision:

> the Tribunal concluded that gas and electricity were not substitutes (though to some extent, demand for gas related to demand for electricity) and that a separate natural gas market existed with competition from other forms of energy at the margins.

Second, in the Duke EGP decision, the Tribunal said:

> There were virtually no differences in the submissions and economic evidence about the definition of the two relevant markets, which drew on the Tribunal's market determination in [the AGL Cooper Basin supply arrangements decision] to some extent. It was agreed that the product of concern is mainly gas as there is little competition between energy sources at this time (Duke EGP decision 2001, paragraph 77).

Market development activities

In some circumstances, gas suppliers may find it profitable to restrain their ability to exercise market power for a time in order to develop new markets. Two specific applications of this argument have arisen in recent times. First, in the case of the Eastern Gas Pipeline (EGP), the Australian Competition Tribunal was 'not satisfied that coverage would promote competition in the regional markets over the existing

55 NCC (2002), *Submission to Parer Review*, p. 60.
56 NCC (2002), *MSP decision*, pp. 105-6.

access terms and conditions'.[57] In reaching this view the Tribunal had regard to the following considerations:

> 125 There are several places south of Canberra on the EGP for which the EGP will be the only source of gas. Prior to the construction of the EGP these places had to rely on electricity or other forms of energy but now have the opportunity to use natural gas…
>
> 126 The EGP has created a gas sales market, and increased competition in the energy market, in places which were not previously served by a pipeline…
>
> 132 ... In addition, there is the fact that these are new markets for gas which EGP is attempting to develop, in competition with the currently available forms of energy. In these circumstances the prices that EGP can charge for transport will be constrained if market development is to be successful. And there is the threat of regulation, with its associated costs, if prices are increased.

Second, in the case of the Tasmanian gas distribution system the Tasmanian Government has selected Powerco Ltd as the preferred developer and offered Powerco a limited exclusive franchise right. In opting for this approach the Government has taken the view that State-based regulation of gas distribution prices will not be required:

> Prices will largely be determined by competition from competing fuel sources within the Tasmanian energy market. The key principle underlying government policy in relation to gas distribution is that the distribution of natural gas is dependent on the successful sale of gas to consumers. In this regard, natural gas is simply one energy source within the competitive energy market, competing against other forms of energy such as electricity, coal, fuel oil, LPG and wood. Therefore, it will be necessary for gas distribution access charges to be competitive within this energy market. In this environment, the gas distributor will not have market power within the overall energy market, even where it has an exclusive right to distribute natural gas, due to competitive pressure from other energy sources.[58]

The cellophane trap

When determining the appropriate market definition for energy products it is important to consider the possibility of a 'cellophane trap'. The essence of the cellophane trap concept as described in Landrigan (1996) is summarised as follows:[59]

- In the US case of *United States v E I Dupont de Nemours* the US Supreme Court had to determine whether Dupont had monopoly power.
- In delineating the relevant product market the Court held that cellophane was reasonably interchangeable for other flexible wrapping materials.
- However, other wrapping material was substitutable for cellophane only because Dupont was charging monopoly prices.
- By focusing on the prevailing price instead of the competitive price, the Court misinterpreted Dupont's monopoly behaviour as competitive pricing.
- In economic terms, at its profit maximising output and price a monopolist faces highly elastic demand. If the monopolist priced according to costs it would face an inelastic demand and have considerable market power.

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57 ACompT (2001), *EGP*, para. 133.

58 Parliament of Tasmania, House of Assembly, *Hansard*, (29 May 2003, 3.01pm).

59 A useful summary of the cellophane trap concept is found in Landrigan, Mitchell G (1996), 'Is the Australian Rugby League Wrapped Up? … Section 46 of the Trade Practices Act and the Cellophane Fallacy', *Trade Practices Law Journal*, Volume 4, pp. 156-160, December 1996.

- The High Court of Australia recognised this concept in *Queensland Wire Industries Pty Ltd v BHP Pty Co Ltd* when it stated that 'Market power can be defined as the ability of a firm to raise prices above the supply cost without rivals taking away customers in due time'.[60]

Following this reasoning, it may be the case that a gas supplier could be exercising market power even if there is evidence of price competition. For example, if the final supply price of gas is the lowest of all alternative energy sources, then the gas supplier has an incentive to price up to the cost of the next best alternative. If the cost of supplying gas is considerably below the cost of its next most efficient alternative, then the gas supply chain may be able to accrue substantial monopoly profits.

Thus, the extent to which alternative energy sources will constrain the exercise of market power by a pipeline owner will depend on the circumstances of each energy source including the underlying cost functions. Therefore, the appropriate market delineation will depend on the specific circumstances in each case.

Barriers to entry

Barriers to entry for gas pipelines are substantial. Some of the factors that constrain new entry include large upfront sunk costs, long term transport contracts, first mover advantages and the natural monopoly characteristics of the industry which would result in higher per unit costs if there is more than one supplier. Access to easements and regulatory approvals may also inhibit new entry.

Countervailing power

In some circumstances, an entity may face an effective constraint on its pricing ability as a result of countervailing power on the part of customers or upstream suppliers. This possibility has been recognised in the Productivity Commission's Part IIIA review:

> … where there is a small number of large users, those users may have considerable countervailing market power. In such circumstances, the scope for the service provider to charge monopoly prices may again be limited.[61]

In support of this claim, the Productivity Commission cited a statement by Epic Energy that:

> The market will dictate the prices which are acceptable. The customers we are dealing with are large sophisticated buyers who have the ability to choose their source of supply and to negotiate suitable contracts …[62]

However, the ACCC 'does not consider that countervailing power is synonymous with a small numbers of buyers (suppliers)'.[63] The key to countervailing power is predominantly the ability of the customer to bypass the supplier.

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60 *Queensland Wire Industries Pty Ltd v BHP Pty Co Ltd* (1989) 167 CLR 177.
61 Productivity Commission (2001), *Part IIIA*, p. 44.
62 Productivity Commission (2001,) *Part IIIA*, p. 97.
63 ACCC (1999), *Merger guidelines*, p. 51.

> Countervailing power exists where a supplier (buyer) faces a buyer (supplier) with market power or a credible threat of vertical integration (or other form of bypass) or direct importing.[64]

The ACCC notes that a detailed consideration of the issue of countervailing power has been undertaken in the NCC report on the MSP.[65] In this context, the NCC concluded that 'absent coverage, the MSP is therefore likely to have sufficient market power to charge monopoly tariffs for shipping Cooper Basin gas'.[66]

Dynamic characteristics of the market

The Parer Review observed that the gas market is immature but developing. In this context, market power will not be a static phenomenon. In some cases the construction of new pipelines may erode the market power of previous monopolists. In other cases market power issues may arise as growth in gas demand causes pipelines to approach capacity constraints.

Constrained capacity

In the case of mature pipelines, the ability to exercise market power may be enhanced as demand for transport approaches the full capacity the pipeline. In these circumstances, the pipeline owner can exploit competitive tension between existing users and new users to force up the price of access. In the absence of regulatory intervention over the price of expansions, the users will bid up the price of the expansion to the cost of the next best alternative whether that is an alternative gas pipeline or another energy source. So long as the cost of the expansion is below the cost of the next best alternative, the pipeline owner will be able to accrue monopoly profits in respect of the expanded capacity.

In many cases the costs of providing additional capacity on an existing pipeline will be below the average cost of the existing capacity. In these circumstances, it would not be unreasonable to expect prices to fall for all users as throughput increases.

In some circumstances the pipeline owner may also be able to inflate the price of access to the existing capacity of the pipeline. For example, when transport contracts approach their termination date then that capacity becomes available for allocation to other users. If there is excess demand for that capacity then each user and potential user will have an incentive to bid up the price to the level of the next best alternative. This situation is compounded because existing users of the pipeline with dedicated gas infrastructure have a strong incentive to continue to utilise gas owing to the costs of switching to alternative energy sources.

Arguably an example of such an attempt to exercise market power has arisen in the context of the Dampier to Bunbury Pipeline. Epic Energy has been reported to be seeking higher prices from its customers in order to guarantee uninterrupted supplies of gas. In the West Australian it was reported that:

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64 ACCC (1999), *Merger guidelines*, p. 51.
65 NCC (2002), *MSP decision*, see paras. 7.132 to 7.196
66 NCC (2002), *MSP decision*, para. 7.196.

> EPIC Energy, owner of the Dampier-to-Bunbury gas pipeline, is in advanced negotiations with WA's biggest gas users over a radical plan aimed at circumventing the controversial price ruling last month by the regulator.
>
> Epic said yesterday the deal would give it the financial return it needed from the pipeline to justify investing in a $300 million expansion, ensuring that key users would have access to additional gas supplies.
>
> Under Epic's proposal, gas users such as Alinta, Western Power and a string of manufacturers would agree to pay Epic more - probably up to 10 per cent - to transport their gas than the regulator's decision requires them to pay …
>
> The pipeline is now operating at maximum capacity and Epic, which paid $2.4 billion for it in 1997, is refusing to expand the line unless it is allowed to raise transport prices.[67]

Service standards and terms and conditions

Any exercise of market power need not be constrained to price effects. Market power may also be exercised by a reduction in service standards or through onerous terms and conditions. This was a concern in the ACCC's consideration of the proposed access arrangement for the Moomba to Adelaide Pipeline System where there was significant concern on the part of users that Epic Energy might have been exercising its market power through the imposition of onerous terms and conditions.[68]

Maximising throughput

In recent years, a misconception has arisen that firms in the gas industry face a universal incentive to maximise throughput on their pipelines, especially where the firm is not vertically integrated. For example, in the Productivity Commission's Review of the National Access Regime, the Australian Council for Infrastructure Development (AusCID) is cited as stating that:

> Infrastructure owners which control a single asset with no vertical integration upstream or downstream … have every incentive to increase the number of customers they provide services to and to maintain quality service delivery. (sub. 11, p. 11)[69]

Similarly, APIA commented:

> Access is more certain in industries that have ring fencing (eg. gas pipelines) or a structure where owners and users of assets are separate (ie no vertical integration). In these industries it is not in the asset owner's interests to impede access. (sub. 32, p. 7)[70]

This argument was also raised by NECG in its submission to the NCC on the revocation of coverage of the MSP:

> … the high fixed and sunk nature of pipeline costs can increase the bargaining power of customers, as the pipeline owners have strong incentives to offer reasonable prices in order to fill capacity (an incentive which is emphasised when competing against other pipelines).[71]

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67 The West Australian (25 June 2003), *Epic plots new gas deal*, p. 53.
68 ACCC (2001), *MAPS Final Decision*, pp. 113-4.
69 Productivity Commission (2001), *Part IIIA*, p. 51.
70 Productivity Commission (2001), *Part IIIA*, p. 51.
71 NECG (August 2001), *Report in support of application to the NCC for revocation of coverage of the Moomba to Sydney Pipeline*, p. 21.

This is a fallacy. Pipeline owners face the same incentive as every other business owner, that is, to maximise profits. Thus, pipeline owners that possess market power will choose the combination of prices and throughput that maximises their profits, not the combination that maximises throughput per se.

In addition, to the extent that a pipeline constitutes a bottleneck facility the owner will also face incentives to capture rents in upstream and downstream markets as observed by the NCC:

> … as further research has evolved in this area of regulation, it has become apparent that access can be just as substantial a problem for structurally separated essential facilities, as for those that are vertically integrated. This is largely because an essential facility owner will always face incentives to seek any rents available in upstream and downstream markets, and vertical integration is not the only means by which the facility owner may be able to capture these rents. For example, contractual arrangements can be used to achieve the same outcomes as vertical integration. (sub. 43, p. 58)[72]

There may be some circumstances where the pipeline owner can maximise profits by maximising throughput. For example, in a fully vertically integrated gas market where the gas supplier is able to perfectly price discriminate, the efficiency maximising throughput and the profit maximising throughput may coincide. However, in most practical circumstances it can be expected that profits will be maximised by restricting throughput.

Market-based tariffs

Elements of the gas industry have advocated a greater role for market-based tariffs in determining price levels. For example, Epic Energy has stated that:

> There should be no regulatory oversight in situations where the capacity being sold is new and tariffs are a product of market based negotiations, not only for new pipelines but also for the expansion of existing pipelines.[73]

In support of this position, Epic Energy submitted that:[74]

- New assets are contestable projects prior to their construction.
- New pipelines and augmentations to existing pipelines are likely to offer competition in the form of competing supply or competing energy sources.
- Any new pipeline or an augmentation of an existing pipeline does not come with a pre-existing customer base.
- It is not in the interests of a non-vertically integrated business such as Epic Energy to block access to its pipelines.

However, the efficiency of a market-based tariff can not be assessed in abstract but rather must be considered in the context of the specific circumstances and bargaining position of each party. Market-based tariffs may be subject to an exercise of market power in certain circumstances. This is particularly likely to be the case where capacity

[72] Productivity Commission (2001), *Part IIIA*, p. 51.
[73] Epic Energy (May 2002), *Submission to Parer Review*, para. 1.8.1
[74] Epic Energy (May 2002), paras. 5.4.32 to 5.4.35

on an existing pipeline is constrained and the next best alternative is significantly more expensive than expanding the existing pipeline.

Even if there is competition in the construction phase of a pipeline, the eventual pipeline owner may still exercise market power unless third party tariffs are locked in as part of the competitive process. There may also be an incentive for the upstream or downstream users to share rents with the pipeline company in order to restrict competition in dependent markets.

Vertical integration

The negative consequences of market power are compounded where vertical relationships are present. In these cases, firms possess an incentive to increase prices to inhibit competition in upstream and downstream markets or they may deny access altogether in order to favour their vertical associates. These potential outcomes have been recognised by the Productivity Commission in its review of the National Access Regime.[75]

Where market power is exercised in this manner, competing firms face an incentive to duplicate the asset. In the Productivity Commission's review of National Access Regime, the Productivity Commission did not regard the likelihood of socially wasteful duplication to be high.

> This suggests that, in an unregulated environment, socially wasteful duplication of essential infrastructure will not be common. In turn, this implies that, from an access policy perspective, the key issues will relate mainly to any adverse consequences of ongoing supply of those services by a single entity.[76]

However, the Productivity Commission went on to observe that the gas transmission industry in Australia has arguably already been the subject of socially wasteful duplication.

> However, this is not to argue that socially wasteful duplication resulting from failure to secure access at 'appropriate' terms and conditions will never be an issue. In this regard, a number of participants referred to the $28 million investment by Duke Energy International to by-pass a section of the existing gas pipeline network in Sydney. Commenting on this investment in a paper prepared for BHP Billiton, National Economic Research Associates (2000a, p. 10) stated that:
>
> Duke's pipeline will traverse almost exactly the same route as the bypassed portion of AGLGN's system, even to the point of using the same right-of-way in many places. Horsley Park's is the most blatantly 'uneconomic' bypass we have witnessed anywhere in the world.[77]

In assessing the likely consequences arising from vertical integration it is necessary to examine the current and potential degree of vertical integration present in the gas industry. The ACCC observes that the extent of vertical relationships in the industry is subject to change. For example, some of the firms involved in the construction of the

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75 Productivity Commission (2001), *Part IIIA*, p. 39.
76 Productivity Commission (2001), *Part IIIA*, p. 42.
77 Productivity Commission (2001), *Part IIIA*, p. 42.

SEAGas pipeline participate in other segments of the industry which will bring new vertical issues to the South Australian and Victorian gas industries.[78]

Conclusion on the extent of market power

There are a range of factors and individual circumstances that will interact to determine the prices and throughput of a pipeline. It is therefore necessary to examine market circumstances on a case by case basis in order to assess the incentives facing pipeline owners and to determine the extent of market power.

However, there is evidence to suggest that the incidence of natural monopoly characteristics amongst the mature elements of the gas pipeline industry continues to be substantial. This view is supported by an absence of effective substitutes, high barriers to entry, constrained countervailing power, limited alternative capacity, immature competition and an incentive for pipeline owners to maximise profits rather than throughput. The negative consequences of market power are compounded where vertical relationships are present.

In these circumstances it is appropriate to assume that a significant level of market power is present in mature gas pipeline systems unless individual circumstances indicate otherwise. This is precisely the approach embodied in the coverage criteria within the Code.

3.3 The efficacy of Part IIIA

When considering the ongoing rationale for a specific gas regime it is helpful to consider the outcomes that would be likely to arise should the regime be withdrawn and sole reliance placed on the Negotiate Arbitrate Model (NAM) under the general access regime. The Commonwealth's proposed amendments to Part IIIA have been used as the basis for the ACCC's commentary on the NAM framework.

Efficient access in the presence of market power

In principle, the NAM is intended to facilitate commercial negotiation for access with the threat of arbitration designed to encourage the owner of the bottleneck facility and an access seeker to reach a settlement. However, it is the ACCC's experience with its telecommunications functions that a 'take it or leave it' approach is a common feature of commercial negotiations under a NAM where the access provider possesses market power.

A 'take it or leave it' negotiation tactic indicates limited incentives for the bottleneck owner to conclude effective agreements concerning the terms and conditions of access. This reflects a market power imbalance between the access provider and access seeker and the occurrence of information asymmetries that favour the access provider.[79]

The 'take it or leave it' approach also demonstrates an absence of countervailing market power on behalf of an access seeker. This is due to the absence of a comparable

[78] See SEAGas website http://www.seagas.com.au/

[79] ACCC (August 2000), *Submission to the Productivity Commission Review of Telecommunications Specific Competition Regulation*, p. 86.

alternative to a bottleneck gas transmission facility that would provide a similar service at a similar price.

Should the access seeker and access provider be able to agree terms and conditions for access, then the relative disparity in bargaining power between them is likely to produce a less than optimal outcome compared to access prices that would be determined through a more transparent process. Without recourse to the public interest, a commercially agreed access price is likely to impact on related markets by distorting final end product prices. A higher level of prescription is also warranted in circumstances where the intermediate price is a modest proportion of the final price since access seekers would be unwilling to undertake a costly process in order to eliminate monopoly pricing.

Timeliness

Experiences to date with NAM-type models, indicates that they are a time and resource intensive processes. In relation to the declaration process, the experience has been that the Minister will reach a decision on declaration under Part IIIA within 6 - 7 months from the time that the application is lodged with the NCC.[80] The full process of determining declaration and conducting arbitration could take around 3 - 4 years without appeal to the Tribunal. Where the access provider possesses market power, it has a strong incentive to prolong the negotiation and arbitration process, and access by third parties.

The ACCC's experience in the telecommunications industry under Part XIC suggests that arbitrations can be slow and costly.[81] This reflects the unavoidably resource intensive and time consuming processes due to the complex nature of issues and the need to conduct the hearing fairly.

Appeals to the Tribunal further increase the time that is required to provide access. In the ACCC's experience, appeals to the Tribunal have effectively been re-arbitrations. This outcome produces a system of negotiation and arbitration and then re-arbitration. The Productivity Commission telecommunications report noted that the service provider has a strong incentive to contest any declaration decision, even if there is a strong argument for declaration.

The negotiate arbitrate process is a time consuming process and one that favours the access provider. In contrast, with the completion of most coverage and access arrangement decisions, the Code is well placed to provide a streamlined process for access. The access arrangements that have been approved are providing clear guidance on the terms and conditions that balance the interests of all parties, facilitating commercial negotiation.

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80 NCC (April 2002), *Submission to Parer Review*, Attachment B.

81 ACCC (December 2000), *Submission to the Productivity Commission Review of the National Access Regime*, p. 13.

Access arrangements

Experience with access regulation is relatively new in Australia and it can be expected that as expertise is gained, aspects of access regulatory regime will be more quickly administered. This is the experience of the ACCC which has commenced assessing the second round of access arrangements, referred to as access arrangement revisions.

The ACCC commenced consideration of the GasNet access arrangement revisions for the Principal Transmission System (PTS) in February 2002 with a final approval issued in January 2003. The ACCC also considered the access arrangement revisions for the independent system operator of the PTS, the Victorian Energy Networks Corporation (VENCorp) commencing February 2002. The access arrangement revisions submitted in response to the draft decision incorporated the required amendments. The access arrangement revisions assessment was completed in November 2002.

The decline in the length of time to consider the second round of access arrangements is also reflected in the work of the Victorian gas distribution access regulator, the Essential Services Commission (ESC). In Victoria the three gas distributors (Multinet Gas, TXU Networks and Envestra) submitted their access arrangement revisions, in April 2002 and final approvals were issued in the 2003 review of gas distribution access arrangements. As yet, no other gas distribution regulators have moved to assess access arrangement revisions.

Due to experience in the first round of access arrangements the ACCC has been able to reduce the time take to progress from the lodgement of the access arrangement to the release of a final approval. In addition the ESC, was able to release its final approvals for the Victorian gas distributors in a similar time period. These outcomes reflect that the most contentious aspect of the first access arrangement, establishing the initial capital base has been determined. Furthermore, there appear to be minimal incentives to delay access as the provisions of the first access arrangement remain in place until the proposed revisions have been approved.

Multiple users

As the gas market continues to develop it can be expected that a greater number of gas suppliers and customers will seek access to the pipeline system. This trend will accelerate to the extent that competition develops in the upstream and retail segments. The NAM is not well placed to support access by a large number of small users. The Code overcomes this potential shortcoming by providing a model set of terms and conditions to balance the negotiation positions of the owner of the bottleneck facility and the users. This is effectively a single upfront arbitration.

The higher level of prescription employed in the Code is appropriate given the expectation that access would be facilitated for a growing number of upstream and downstream parties. The prescription of access avoids high transaction costs as the number of access seekers increases.

Contractual Pancaking

In a study into the European gas industry, the Brattle Group identified the occurrence of sequential access negotiations to transport gas across Europe and within some countries. They denoted the repetition of access negotiations as 'contractual pancaking'. The Brattle Group report recommended eliminating this conduct through the introduction of standard gas transportation contracts for basic services to avoid extensive access negotiations.[82] Such outcomes are analogous to access arrangements.

It is possible to imagine 'contractual pancaking' occurring in Australia should the Code be removed. For example, transporting gas from the Cooper Basin to Melbourne would require negotiating access to the Moomba to Sydney pipeline, then the GasNet System and then through up to three distribution networks in metropolitan Melbourne. Potentially such an outcome would impede the development of inter-basin competition, adversely affect the final end price of gas for users and undermine the intent of 'free and fair' trade in gas initiatives agreed to by CoAG in 1994.

In contrast to the potential occurrence of 'contractual pancaking' under the NAM, the Code offers scope for commercial negotiation but, importantly, provides a timely mechanism to resolve access disputes. The Code offers the opportunity to avoid the extensive and timely negotiations, arbitrations and appeals that appear the likely outcome from the operation of the NAM. The Code provides for benchmark terms and conditions to avoid contractual pancaking and provides for more efficient access to assist the development of competition in related markets.

Information disclosure

In contrast to the NAM which requires some information disclosure, the Code provides third parties with the capacity to make informed decisions regarding their negotiations with service providers. The Code also provides for the use of an access arrangement to disclose benchmark terms and conditions for access including price for a set period of time. This is enhanced through the information disclosure requirements that are contained in Attachment A and section 5 of the Code.

The information disclosure provisions of the Code appear to effectively attenuate the information asymmetry between the service provider and third parties facilitating commercial negotiation. Importantly, they also reduce the information asymmetry between the service provider and the regulator and arbitrator. This provides the arbitrator with more information upon which to make a decision.

Dispute resolution

The Code establishes a mechanism whereby disputes between prospective users and the service provider about the terms and conditions of access, including price can be submitted to the ACCC for resolution, in its role as the arbitrator under the Code. Though the disputing parties may agree on terms and conditions, including prices that are different to those in the access arrangement, the approved access arrangement terms and conditions are the default benchmarks that will be used to resolve the dispute.

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[82] Brattle Group (2001), *Third-Party Access to Natural Gas Networks in the EU*, p. 44.

Terms and conditions, including price approved through the access arrangement process provide a more effective means of dispute resolution compared to what might be determined through alternative dispute resolution mechanisms. Specifically, the process of determining reference tariffs and reference service along with attendant terms and conditions reduces the information asymmetry between the decision maker and the service provider through a public and transparent process of determining those values. By contrast a commercial arbitration is still affected by the information asymmetry and the lack of detailed information on cost and other relevant information. The information available through approved access arrangements facilitates commercial negotiation by providing parties with information on the position that would be adopted by an arbitrator.

Vertical relationships

In addition to restraining the bargaining and monopoly pricing power of service providers, the Code has provisions that seek to attenuate the incentives for vertically integrated service providers to misuse ownership of their monopoly asset to affect competition in related markets.

The NAM does not offer the same level of protection in this area as the Code. The additional provisions incorporated in the Code are important as the gas industry makes the transition from a series of State-based vertically integrated monopolists to a more competitive environment.

Ring fencing

Ring fencing provisions in the Code require that related businesses of a service provider be segregated from its non-gas transportation service activities. Service providers must comply with procedural and reporting requirements to enable assessment of adherence to the ring fencing obligations under section four of the Code. Since May 2001 the ACCC has required service providers to submit annual ring fencing compliance reports that describe a service provider’s level of compliance.

Associate Contracts

Under the Code, associate contracts are contracts, arrangements or understandings between service providers and their associates for the provision of services from a covered pipeline. It also includes those contracts, arrangements or understandings that service providers have with anyone for the provision of services from a pipeline covered by the Code where that contract provides a direct or indirect benefit to an associate and is not an arm's length transaction.

Associates are not regarded as such merely because they have entered into a contract, arrangement or understanding with a service provider. Where a service provider is a corporation, for example, its associates include all related corporations, the directors and secretaries of related corporations, plus the directors and secretaries of the service provider itself (see *Corporations Act 2001*).

A service provider must obtain approval from the regulator for an associate contract to be enforceable. The regulator can only refuse to approve an associate contract if it substantially lessens, prevents or hinders competition in the market, or is at least likely

to do so. The regulator must conduct public consultation as it sees fit. Public consultation can only be avoided if the associate contract uses the reference tariff for the provision of services.

Conclusion on the efficacy of Part IIIA

The ACCC recognises that there is a case for the retention of both an industry specific and a generic access regime, although the hierarchy of such regimes should be established to recognise that industry based regimes represent the first step in a longer reform process that might see a generic regime eventually replace all others in a more competitive environment.

The Code has been developed to be consistent with Part IIIA while addressing the specific needs of the gas industry. It establishes a process that is more accessible for multiple access seekers than would operate under the generic provisions of Part IIIA. It also requires access arrangements to meet criteria that are more specific to the needs of the industry than the criteria that would apply either to an undertaking or an arbitration determination under the generic provisions of Part IIIA.

The NAM under Part IIIA suffers a number of deficiencies in circumstances where the access provider possesses market power. In particular, the NAM introduces incentives for the access provider to delay the process and adopt a 'take it or leave it' approach to negotiation. By contrast the Code provides a framework that facilitates commercial negotiation.

When the Code was being developed consideration was given to the adoption of a NAM. However, for similar reasons to those outlined above the Code developers considered that the reference tariff approach would be more effective than the NAM.

To date the flexibility offered by the co-existence of Part IIIA with stand-alone legislative access regimes has enabled access regimes suited to the particular needs of each industry to be developed at appropriate levels and by relevant parties. This approach has provided advantages for pipeline companies by including provisions that are able to accommodate their unique needs. The ACCC considers that industry specific regimes are appropriate for industries where competition is developing as is the case in the gas industry.

The ACCC accepts that over time there is likely to be a reduction in the number of pipelines covered by the Code: this will be driven by changes in the market that mean the coverage criteria no longer apply to some pipelines. In that context the Code has an implicit 'sunset' clause for its useful life. In that instance sufficient competition may have developed such that reliance upon a generic access regime rather than industry specific framework will have become more appropriate. It is the ACCC's view that an industry specific regime represents an intermediate step from no competition to a market that is more competitive. In effect, Part IIIA is a reserve system in this transitional phase.

3.4 Price monitoring

The Code and Part IIIA incorporate provisions for price control through establishing access prices for essential services and facilities. In addition to that form of economic regulation, other instruments can be used to examine, monitor, influence or control prices of businesses. These include price notification, price monitoring and government or independent inquiries into pricing.[83] The Productivity Commission has recently completed a review of the *Prices Surveillance Act 1983* (Cth) (PSA) and considered these forms of economic regulation as part of that process.

However, price monitoring is not effective in circumstances where a facility exhibits natural monopoly characteristics and possesses market power. Consequently, in the case of the gas industry where elements of the industry continue to possess substantial market power, price monitoring would not be an effective substitute for the current regime. This is the case because price monitoring does not provide a mechanism for adjusting behaviour and facilitating access on reasonable terms and conditions. In addition, price monitoring does not provide a mechanism for reducing prices in an environment where costs are declining. If price monitoring is combined with a threat of future regulatory intervention then such an approach increases the level of regulatory risk.

Price monitoring is a reasonably resource intensive process and may require the same level of resources as the current regime. This is especially the case where a judgement needs to be formed on the reasonableness of the prices imposed.

However price monitoring may have a role where coverage is not warranted. Amongst its suggested reforms to the PSA, the Productivity Commission recommended that some form of prices monitoring might be required for facilities not declared under Part IIIA due to a concern that remnants of substantial market power may persist in markets of national significance not covered by Part IIIA. The Productivity Commission was of the view that there is a case for mechanisms to address concerns about possible monopolistic pricing in such markets.[84]

The NCC in its submission to the Productivity Commission's review of the national access regime suggested that price monitoring could be an additional option in relation to declaration, such that the NCC and Minister could decide to declare, price monitor or not declare a facility.[85] Similar provisions could also be included in the Code, with the decision by the Minister to cover, uncover or price monitor certain pipeline services. However, it would not be appropriate for price monitoring to replace the current regulatory environment in circumstances where the coverage test is met. Price monitoring would only be warranted in circumstances where the coverage test was not met. In its telecommunication report the Productivity Commission also suggested that the prices monitoring could also be used to 'effect a transition from regulated prices under declaration to deregulation'.[86]

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83 Productivity Commission (2001), *Telecommunications*, p. 3.
84 Productivity Commission (2001), *Review of the Prices Surveillance Act 1983*, p. xviii.
85 Productivity Commission (2001), *Part IIIA*, pp. 38-39.
86 Productivity Commission (2001), *Telecommunication*, p. 297.

In contrast, the Productivity Commission in its review of the national access regime was more reserved in relation to such an option for the national access regime suggesting such an option was not warranted at this stage of the development of Part IIIA but could be incorporated into industry specific regimes.[87] This option would also complement recommendations of the Parer Report which recommended minimum requirements be developed to ensure that pipelines not covered by the Code introduce a range of market supporting mechanisms such as tradeable capacity, ring fencing and the requirement to post prices.[88]

The inclusion of price monitoring functions within the TPA could complement the existing provisions of the Code and Part IIIA; specifically as the Productivity Commission has previously stated:

> … it raised the possibility of monitoring because it has serious reservations about the decision that recommended the EGP [Eastern Gas Pipeline] be covered under the Gas Code. While the Commission considered that the implied reason for recommending coverage – the potential for parallel pricing – was difficult to sustain given the existence of what appeared to be a *competing* facility, it nonetheless felt that, in the light of the NCC's inclination to declare such a facility, price monitoring would have provided the option for a less prescriptive response.[89] (emphasis in original)

87 Productivity Commission (2001), *Part IIIA*, p. 197.
88 Parer Review (2002), Recommendation 7.5, p. 221.
89 Productivity Commission (2001), *Part IIIA*, p. 197.

Chapter 4 ACCC approach to regulation

The coverage criteria of the Code are designed to ensure that only pipelines with natural monopoly characteristics and market power are subject to access regulation. If a pipeline is not covered under the Code then commercial negotiations establish the terms and conditions of access, including price. Furthermore access prices may be determined through a tender process approved under the Code.

If a pipeline is covered by the Code the owner is required to submit to the regulator an access arrangement for approval. The access arrangement establishes benchmark terms and conditions, including price, for reference services in the event that access negotiations break down. The primary intent of the Code, through the approval of access arrangements is to facilitate commercially agreed access through the disclosure of sufficient information to assist parties in negotiations. The Code is not intended to be a substitute for commercial access.

Some sections of the gas industry have criticised the administration of the Code, particularly in relation to the access arrangement process. Industry views on the administration of the Code are reflected in the views of the AGA:

> Since the introduction of the National Gas Code regulated businesses have experienced significant intrusion into their business operations. The nature of the cost of service model contained in the Code, and its application by regulatory authorities has resulted in a heavy-handed form of regulation that is inconsistent with the original intent of the Code.[90]

However, any economic regulation that imposes a requirement for prices to be determined on a fair and reasonable basis will require some level of intrusion into the affairs of business operators. Indeed, for regulation to be effective it must have the effect of modifying the behaviour of firms in the industry. In the case of the pipeline industry once a decision has been made to cover a pipeline, the modified behaviour that is sought will be a reduction in prices that limits the capacity of the operator to exercise its market power and accumulate monopoly profits. From the perspective of a pipeline operator, any regulatory framework that is effective will be perceived to be intrusive because it will necessarily lower the earning potential of the business.

The Code as currently drafted incorporates a range of mechanisms to ensure that the interests of all parties are given weight and balanced. These requirements ensure that the Code does not interfere with the interests of pipeline operators any more than is required in order to reasonably restrain the exercise of market power. Further, the ACCC's application of the Code can best be characterised as a balancing process. The following sections document the ACCC's approach to regulation and demonstrate the points at which discretion has been exercised in order to balance interests.

[90] The Australian Gas Association (April 2002), *Submission to the Energy Market Review: Key issues for the Energy Market Review, Response to the Issues Paper*, p. 45.

4.1 The building block approach

Once a decision has been made to regulate a particular asset, the Code provides a flexible framework within which each service provider nominates a regulatory approach that best meets its specific circumstances. It is the role of the regulator to assess a service provider's proposed access arrangement against the general principles and objectives set out in the Code. The ACCC encourages a form of regulation that is best characterised as incentive regulation.[91] Initially, the ACCC approves a framework access arrangement that provides a benchmark for negotiation between the operator and users. Should the regulated entity outperform the benchmark approved by the ACCC by growing the market or operating the pipeline more efficiently, then the entity is permitted to retain the higher earnings.

The building block approach described in the Code has been found by the ACCC and other regulators to be an appropriate model to assess service provider's proposals. This has been important because efficient prices for gas and electricity businesses were unlikely to exist at the commencement of regulation and there was limited price and benchmarking information. This approach establishes an appropriate benchmark that fully compensates the regulated business for the efficient costs of providing the regulated service.

The ACCC uses the building block approach in accordance with the Code to establish reference tariffs for reference services only. The Code only applies to those services that are covered by an access arrangement and does not have to apply to all of the services provided by a pipeline business.

The building block approach accounts for each cost category faced by the service provider and in its simplest form, sums each of the categories together to determine the revenue required to cover the service provider's reasonable costs. The key building blocks are:

- Depreciation – represents the return of the capital investment in the pipeline to owners over the life of the pipeline. Apart from the constraint that each pipeline may only be depreciated once, there is considerable flexibility available in the time profile of depreciation to smooth the revenues over time or to achieve desired price paths.
- A return on equity – calculated through the capital asset pricing model (CAPM). The CAPM is discussed in more detail below.
- The cost of debt finance (return on debt) – is calculated by adding a premium or debt margin to the 'risk free rate'. The return on debt represents the interest payments required to service borrowings. The combination of the return on equity and the cost of debt finance is often referred to as the weighted average cost of capital or the WACC.
- Non-capital costs including operations, maintenance and administrative costs associated with the day to day running of the business.
- Net taxation liabilities – this cost component is calculated by applying the relevant statutory tax rates to regulatory cashflows, subtracting an assumed valuation of imputation credits. Importantly, the component for taxation may not equal the

[91] However, the Code provides flexibility in the type of regulation that a service provider can nominate. For example, the service provider may choose a cost of service model under s.8.3(a).

company's actual taxation liability as the regulatory accounts are for a notional, standalone pipeline.

Regardless of the form of economic regulation some method of establishing initial access prices is required. Primarily due to its incentive properties, the building block approach represents a superior approach to its main alternative, rate of return regulation. Accordingly, the building block approach represents an appropriate method to determine the initial access charge which can be rolled forward and possibly used as a base price in conjunction with other pricing options.

The building block approach uses efficient costs which are derived through a benchmarking process of actual costs. This approach has been adopted to reduce the dependence on historical costs which may reflect past monopoly inefficiencies of the business. This is of particular relevance for Australia where, at the commencement of regulation, many energy infrastructure assets had been government owned and there was little information about appropriate prices. In this context a level of information disclosure, as contained within the Code's minimum obligations, was considered to be appropriate to assist third parties in negotiating access and to assist the regulator in determining reference tariffs.

The ACCC's application of the Code has tended to be applied with reference to benchmarking of relevant cost data and is complemented by the use of market data where appropriate or required by the Code. This implicitly entails a light-handed approach to regulation. However, service providers, third parties and others contribute to the access arrangement approval process by suppling information and requesting specific costs be recovered or disallowed; collectively these actions may create a perception that the Code is not light-handed.

Price paths

In particular circumstances, it may be desirable to set a particular price (reference tariff) path rather than simply charging the cost in a particular year. For example when a pipeline is entering a new market, it may be desirable to charge lower tariffs initially in order to grow the market. Such an outcome can be accommodated through adjusting the depreciation component of revenue. The depreciation profile may also be adjusted to reflect the risk of by-pass or stranding for the whole transmission pipeline or a specific part of the pipeline, such as a lateral.

Depreciation is a notional cost in any particular year of the pipeline's operation. As long as the service provider is able to recover the total investment in the asset over the life of the pipeline, the depreciation amount in any particular year may be of little importance across a wide range of possibilities. While there is a degree of flexibility under the building block approach with respect to the elected tariff path and depreciation profile, they are dependent on each other such that for a given period either the depreciation profile or the tariff path can be elected, not both.

Each of the building blocks set out above is summed together to calculate and forecast the reference tariff and revenue required to cover the total cost of providing the

reference service(s).[92] Revenue is then divided by forecast demand to calculate a reference tariff in accordance with the provisions of the Code. The reference tariffs as approved by the ACCC for the access arrangement period represent forecasts.

Incentive regulation

The ACCC's application of the building block approach sets target benchmarks across the service provider's costs. If the service provider is able to beat those targets, through more efficient operations or greater actual volumes than forecast, then those gains can be kept by the firm. In contrast, rate of return regulation provides no such incentives. Importantly, the Code provides for no scope for regulators to review access arrangements once they have been established.[93]

Incentive regulation gives discretion to the service provider to operate its business and allows it to benefit from returns greater than those anticipated by benchmark parameters. It is expected that this form of regulation will enable the market to grow and facilitate new services to be developed to meet the needs of users while operational and capital costs are minimised. In relation to the ACCC's approach to regulation Moody's noted:

> Importantly regulators [Essential Services Commission and ACCC] continue to apply incentive-based methodologies that encourage companies to more efficiently operate their networks. At the same time, the companies are allowed to keep certain portions of their efficiency gains – the excess over the regulator's operating costs, capital expenditure and cost of funds targets.[94]

Applying the building block methodology to service providers has provided the opportunity for the businesses to move toward more efficient structures, operations and pricing over time while passing on some of these benefits to users. This is important to assist firms make the transition to a more competitive environment. The building block approach also incorporates mechanisms that give it additional incentives for service providers to increase their performance. These are discussed below.

Length of regulatory period

Reference tariffs are forecast for the relevant access arrangement period which is typically five years, but pipeline operators may elect a different period depending on the particular circumstances of the individual service provider. There is, however, debate about the appropriate length of the regulatory period, this is largely a result of attempting to allow sufficient time for a firm to retain any gains above the building block reference tariffs while seeking to ensure that prices reflect efficient costs. It is considered that a five year access arrangement period strikes the right balance in most instances.

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92 As foreshadowed above, it may be the depreciation component that is calculated on the basis of the desired price path rather than the tariff by simply summing together each of the building blocks.

93 Notwithstanding certain exceptions such as trigger mechanisms as discussed below.

94 Moody's Investors Service (July 2003), *Australian/NZ Regulated Distribution and Transmission 2003 Outlook: Stable but event risk to drive some credit profiles*, p. 3.

Increasing the length of the regulatory period can increase the power of the incentive scheme by permitting the pipeline operator to retain efficiency savings for a greater period of time.

Benefit sharing carry-over mechanisms

Under a carry-over mechanism, each year's efficiency gain (loss) is calculated by taking the actual reduction (increase) in expenditure minus the reduction (increase) in expenditure anticipated for that year at the start of the previous regulatory period. This anticipated efficiency gain (loss) is retained by the firm for the remainder of the regulatory period. Further the access price is adjusted at the subsequent reset so that the service provider carries the efficiency gains (losses) for a predetermined number of years, regardless of when they are achieved. In addition to the carry-over mechanism, the percentage share of gains (losses) between the firm and users must also be determined.[95] Another element of the sharing mechanism is the equal treatment of gains and losses, with the firm being responsible for the same percentage of any loss as well as any gain.

Cost-pass through: "Z" factor

In general terms a service provider's costs can be divided into two broad categories, those that it can control and those that it can not. To remove the potentially negative impact of certain costs that are beyond the control of the firm, price or revenue frameworks may allow for certain costs to be passed onto third parties. This practice is referred to as 'cost pass-through', expressed as a "Z" factor[96] and may provide for total or partial transfer of costs. The use of "Z" factor has been employed in some access arrangements and is most commonly used in relation to taxes and other government charges. The latest GasNet access arrangement has an extensive pass through mechanism that includes items other than taxes.

Off-ramps

An 'off ramp' describes the circumstances under which the approved access arrangement could be opened for review by the regulator, in effect triggering a reassessment of reference tariffs. 'Off ramps' are intended to safeguard users against excessive pricing by the service provider and protect the firm from financial distress in adverse economic circumstances. The Code provides for the inclusion of 'off-ramps' in gas pipeline access arrangements. The Tribunal has upheld the right of the ACCC to include 'triggers' in access arrangements. The conditions under which an off-ramp is activated are set out in the approved access arrangement. An example of such an off-ramp is the inclusion of a trigger in the access arrangement for the NT Gas pipeline for review should Timor Sea gas become available in Darwin.

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95 This share or split is subject to some debate, a range of between 30% – 60% for the service provider with the balance, 70% – to 40%, for third parties being the typical ranges. For further information about rolling carry-over mechanisms see the ACCC (13 Nov. 2002), *GasNet Australia access arrangement revisions for the Principal Transmission System*, p. 272.

96 Farrier Swier Consulting (June, 2002) *Comparison of building blocks and index-based approaches*, prepared for the Utility Regulators' Forum, p. 28.

Certainty and transparency

The ACCC is aware of the importance to investors of a stable and transparent regulatory environment and has worked to minimise uncertainty and maximise the flow of information to investors, service providers and other relevant parties. The ACCC has released several guidelines to minimise uncertainty by educating industry participants and ensuring that the ACCC's intended application of the Code is known. The guidelines mentioned below are available on the ACCC's website.

The Draft Statement of Principles for the Regulation of Transmission Revenues (DRP) was primarily focussed on the electricity industry, however, the principles that are also applicable under the Code have been adopted since the DRP was published. The DRP covers a range of widely applicable issues including valuation principles, depreciation and the cost of capital.

The post-tax revenue model (PTRM) and PTRM Handbook, released in October 2001, were developed and released by the ACCC to demonstrate its approach to calculating benchmark revenue requirements and tariffs under the Code. The PTRM is based on the actual models used to calculate regulatory revenues for gas pipelines regulated by the ACCC, except that it uses a hypothetical example to avoid releasing commercially sensitive information and has been simplified to ensure clear presentation of the concepts employed in the model.

The PTRM was developed to overcome industry perceptions that benchmark regulatory revenues were calculated with a 'black box'. The PTRM has been used by industry and financiers alike to simulate various scenarios. The PTRM Handbook describes each of the spreadsheets and key features within the model.

The ACCC released its Draft Greenfields Guideline in June 2002. The guideline was prepared to ensure prospective investors in the gas industry understand how new natural gas (greenfields) transmission pipelines might be regulated. The ACCC recognises there are unique risks associated with developing new gas pipelines. The guideline seeks to address any perceived risks by creating greater certainty about when a prospective pipeline is covered by the regulatory framework and if regulation applies how potential uncertainty can be addressed.

The ACCC and the NCC developed a joint publication, *Regional development of natural gas transmission pipelines guide*, which assists in addressing issues relevant to proposed gas transmission pipelines to regional communities. The guideline, released in October 2002, was designed to assist local government authorities considering the regulated versus unregulated gas pipeline options available to them.

4.2 Elements of the building block approach

Typically, access arrangements, comments by interested parties and the ACCC's own analysis suggest a range of potential values for certain parameters. In assessing an access arrangement and approving reference tariffs under the Code, there are a range of variables that require judgement to be exercised in order to balance the objectives of the Code and to give appropriate weight to the interests of all parties. The ACCC recognises that investment could be impeded if the regulatory regime places undue financial pressure on asset owners.

Consequently, where there is doubt as to the most appropriate value of such variables, the ACCC has tended to make conservative assessments benefiting service providers to ensure that service providers have access to sufficient resources to continue to operate facilities and undertake new investment. This view is supported by the relative performance of regulated companies against equity markets and the findings of Moody's Investors Service on the regulatory regime in Australia compared to the UK.

This view is supported by ratings agency Moody's which recently stated:

> Moody's believes the experiences of three resets in Australia … gas and electricity transmission in 2002 – have demonstrated that its regulators have indeed adopted a benign stance when setting revenue and returns requirements for T&D [gas and electricity transmission and distribution] companies.[97]

Some examples of the ACCC's conservative assessments are described below.

The CAPM

As outlined above, the building block approach requires the establishment of an appropriate rate of return to equity holders. The ACCC has set the rate of return on equity in accordance with various relevant sections of the Code.

The CAPM is widely accepted and applied across Australian and international capital markets.[98] Given the wide acceptance of the CAPM, that service providers have proposed its use and the fact that the Code uses it as an example of an appropriate model, the ACCC has applied the CAPM to establish the target rate of return on equity in each of the access arrangements it has considered under the Code.

The CAPM formula uses the following variables to determine the required return on equity (RoE):

- The risk free rate (Rf), that is, the return expected from investing in a risk free asset.
- The difference between the expected return of investing in the market (Rm) and the risk free rate, commonly referred to as the Market Risk Premium (MRP) or Equity premium. That is, MRP = Rm – Rf.
- The equity beta (βe) which is a measure of correlation between the return on an equity investment in a particular asset with the return of the whole market (Rm).

The CAPM formula is: $RoE = Rf + \beta e\ (Rm - Rf)$

A fundamental principle of the CAPM requires that investors only be compensated for systematic (or non-diversifiable) risk. This is a result of portfolio theory, a cornerstone of modern finance principles which demonstrates that non-systematic (specific) risk can be diversified away by holding a portfolio of assets rather than a single asset. The equity beta is a measure of the systematic (or non-diversifiable) risk.[99] The only term in the CAPM that is specific to the subject business (that is not a market wide term) is the

97 Moody's Investors Service (Aug. 2003), p. 3.

98 See Allen Consulting Group (July 2002), *Empirical Evidence on Proxy Beta Values for Regulated Gas Transmission Activities*, at pp. 9-10.

99 See Allen Consulting Group (July 2002), at pp. 9-12 and 16-17.

equity beta. Each of the other parameters would be identical regardless of the business or industry to which the CAPM is applied.

Applying the CAPM

As with most economic models, the CAPM makes a range of simplifying assumptions that abstract from reality to some degree in order to predict an outcome with a practical level of input data. These assumptions must be relaxed to apply the CAPM in practice. Consequently, the CAPM is not absolutely precise, and is not without flaw. However, as currently agreed by most academics and practitioners alike, 'while not "perfect", the CAPM is the simplest available model and is as good as any existing alternative.'[100] It is also used by industry in evaluating projects that they are considering undertaking.

The key assumptions of the CAPM that limit precision in application to the Australian capital market are set out below:[101]

- The market portfolio – in theory, the market portfolio includes all risky assets including land, private property and businesses. The market portfolio is approximated in practice by the All Ordinaries Share Price Index.
- The risk free rate – Commonwealth bonds are not a truly risk free investment.
- Normal distribution of returns – the CAPM assumes that returns are normally distributed. That is, returns are explained entirely by their mean and variance. According to Bishop et al,[102] the issue of whether returns are normally distributed in Australia is unresolved.
- The CAPM assumes an efficient market and zero transaction costs – the level of efficiency in the Australian market is unresolved, and clearly transaction costs do exist.
- Investors are assumed to be Australian residents for taxation purposes.

Equity Beta

The equity beta is an input to the CAPM, which is used by the ACCC to establish the benchmark rate of return on equity. The rate of return is critical to the regulatory framework applied by the ACCC as it is used to determine an estimate of the post-tax nominal return on equity which determines whether investors will be willing to provide equity to finance the infrastructure.

To determine the appropriate benchmark return on equity for a regulated asset, it is necessary to abstract from the level of gearing (or debt funding) used by the regulated entity in order to avoid compensating inappropriate financing structures. This is achieved by determining an asset beta, which is the beta that would apply to the transmission asset if it was financed purely with equity.

Once the asset beta has been determined, it is then possible to apply a formula incorporating a benchmark gearing ratio to establish the equity beta to be used in the CAPM. In the CAPM framework, the equity beta is multiplied by the market risk premium – the return expected as compensation for investing in risky stocks over

[100] S Bishop, H Crapp, R Faff and G Twite (2000), *Corporate Finance 4th edition*, Prentice Hall, p. 160.
[101] For further assumptions of the CAPM see S Bishop, H Crapp, R Faff and G Twite, *Corporate Finance 4th edition*, Prentice Hall 2000, section 7.3, p. 145.
[102] S Bishop, *et al* (2000), p. 142.

investing in Commonwealth bonds. The market risk premium typically adopted is 6 per cent.

In its gas transmission pipeline regulatory decisions prior to GasNet and NT Gas, the ACCC has consistently used an equity beta of more than 1.0, which indicates greater risk than that of the whole market. A value greater than 1.0 is not consistent with the widely held view that gas, and electricity, utilities are less risky and more stable than the market average, despite generally adopting a more aggressive gearing ratio. Greater stability in company earnings would suggest that the equity beta should be less than 1.0.

As an equity beta of less than 1.0 is more appropriate given the level of market risk for regulated pipelines in Australia. Individual beta observations, such as those that might be used for a single firm, typically have a large standard error.[103] It is therefore common practice to use beta estimates from a number of proxy companies as a method of reducing the statistical error of the observations. The best proxies to use in estimating a value for beta are companies that exhibit systematic risk characteristics that are as close as possible to the subject company. In the case of gas transmission, the best proxy would be another Australian regulated gas transmission pipeline. Unfortunately, there are a limited number of public companies involved in gas transmission, and many of these have other interests in addition to gas transmission (or comparable activities) which reduces comparability to the target company.[104]

However, a recent review of empirical evidence undertaken by the Allen Consulting Group (ACG) suggests that the value of the equity beta for Australian gas transmission businesses is 0.7. While the data sample available for Australian transmission and distribution businesses is relatively small and potentially not stable, it is growing and becoming more robust. According to ACG:

> 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.
>
> That said, however, we would caution against exclusive reliance upon the latest market evidence at this point in time.
>
> …The use of a proxy beta of 0.7 would represent a substantial reduction in the estimates of the costs of capital compared to the assumptions previously adopted. While such a revision would be warranted in the face of reliable, objective evidence, it cannot be concluded definitively that this quality of evidence exists at this time.[105]

Given this uncertainty, the ACCC has not adopted an equity beta of 0.7. Rather, it has elected to favour the service provider in adopting an equity beta of approximately 1.0 in its most recent decisions. The ACCC may place more weight on empirical evidence

[103] See Allen Consulting Group (July 2002) at p. 13.
[104] See Allen Consulting Group (July 2002) at pp. 18 - 20.
[105] See Allen Consulting Group (July 2002) at p. 42. See p. 43 also. Table B.2 of Appendix B presents the individual Australian beta observations.

when further robust market evidence becomes available. This is consistent with the recommendations of the ACG.[106] The ACCC first indicated that an equity beta below 1.0 was appropriate for electricity transmission assets in its Draft Regulatory Principles:

> A low beta indicates the stock has low risk relative to the market. Conversely a high beta (greater than one) indicates the returns vary significantly more than the market average. It is expected that the equity beta (provided that gearing is not exceptionally high) for TNSP's will be below one because this industry is a low risk industry, that is, it is subject to a regulated income set in a transparent and consistent regulatory framework, with the demand for services relatively resistant to changes in overall economic activity. [107]

The value assigned to beta was an issue due to be considered by the Tribunal in two separate reviews of ACCC determinations under the Code this year for Epic Energy's Moomba to Adelaide pipeline system (MAPS) and GasNet's transmission network in Victoria. Both companies' withdrew their application for review with respect to the issue of beta.

In addition, APT accepted the ACCC's determination of an equity beta of 1.0 for its Amadeus Basin to Darwin pipeline earlier this year.[108] Each of these responses to the ACCC's determinations would suggest that if anything, they overstate the appropriate value for the equity beta. These responses are consistent with the available empirical evidence as presented in the study by the ACG.[109]

Alternate models / wide acceptance of the CAPM

A variety of models have been developed by extending the CAPM and/or relaxing some of its assumptions. Most such models are based on the basic idea of the CAPM but are more complex in form. Notably however, none of the extended CAPM models has overtaken the basic CAPM in terms of wide acceptance and application.[110]

An alternative model to the CAPM and extended CAPM is arbitrage pricing theory (AP Theory). Unlike the CAPM, AP Theory is not based on the concept of a market portfolio. Its foundation is built on the economic law of one price. That is, where assets are perfectly substitutable, they will be priced identically. AP Theory is similar to the CAPM in that both models take account of systematic risk only as non-systematic risk can be diversified away at no cost. AP Theory originated in the 1970s and has been the subject of a significant amount of academic attention.[111] However, despite the resources devoted to its development AP Theory has failed to gain acceptance as a better model than the CAPM:

> It is generally accepted that an economic model or theory that is a cornerstone of a paradigm of belief should not be discarded unless a clearly superior model or theory is available to take its place. The AP Theory has had every opportunity to prove its worth but it has not yet delivered

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106 See Allen Consulting Group (July 2002), at section 4.3.

107 Draft Statement of Principles for the Regulation of Transmission Revenues, ACCC, May 1999, p. 79.

108 *Final Approval for the Access Arrangement proposed by NT Gas Pty Ltd for the Amadeus Basin to Darwin Pipeline*, ACCC 26 March 2003.

109 See Allen Consulting Group (July 2002).

110 S Bishop et al (2000), p. 149.

111 S Bishop, *et al* (2000), p. 159.

> the knock-out blow required. Although the AP Theory still shows promise, its credibility is questioned by the mystery which surrounds the factors. We know that the CAPM is not perfect, but its simplicity and its basic intuitive appeal should ensure its tenure for at least the immediate future. [112]

Compensation for working capital

Businesses typically require funding known as working capital. Working capital is used to bridge the gap in time between expenditure and revenues. In other words, a business will generally have to pay its suppliers prior to receiving revenue from its own customers. While working capital costs are a legitimate cost likely to be incurred by gas transmission businesses, the ACCC has not made an explicit allowance for such costs in its decisions to date. Rather, the ACCC's revenue modelling as depicted in the post-tax revenue model (PTRM) overcompensates for such costs by a number of assumptions, such as the assumption that revenue is not received until the end of the year.

To ensure the ACCC was not under compensating service providers with its approach to working capital costs, the ACCC engaged the ACG to assess the issue. The consultancy report included a case study of the MAPS. The analysis found that revenue calculated using the PTRM approach for the MAPS was overstated by more than 1.0 per cent after taking working capital costs into account:

> A number of plausible assumptions were adopted for the with-in year timing of the cash flows for the Moomba to Adelaide pipeline, and it was found that the simple target revenue formula used in the PTRM overstates the revenue required by about 1.8 per cent (which can be interpreted as the extent to which average prices are higher under the PTRM approach than required). While the results showed that there would be a financing cost associated with operating activities, it is swamped by the favourable timing assumptions with respect to the share of revenue associated with capital costs. [113]

The ACCC has continued to use the PTRM approach to date rather than a more detailed and explicit modelling approach in order to promote transparency and reduce administration costs for both the service provider and the regulator.

Demand forecasts

Once reasonable cost requirements have been determined, it is then necessary to calculate gas transmission tariffs. Under the Code, required revenue needs to be divided by throughput. Australian regulators typically use forecast demand as an estimate of throughput rather than pipeline capacity. NERA has advised the ACCC that the current regulatory practice in the USA is to set tariffs on the basis of defined capacity, and that this approach does not appear to deter new investment:

> US experience indicates that the defined capacity approach does not remove incentives for pipeline service providers to invest; investment in new pipelines and new capacity in the US continues to be robust. However, new pipelines are rarely built without underpinning long-term contracts for the use of the capacity. Moreover, the capacity of newly constructed pipelines is usually all utilised straight away (unless the pipeline developer has made a speculative decision

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[112] S Bishop, *et al* (2000), p. 160.

[113] Allen Consulting Group (March 2002), *Working Capital – Relevance for the Assessment of Reference Tariffs*, p. 2.

> to overbuild, or a user reserves excess capacity for its future anticipated needs). This is consistent with the incentive discussed above for pipeline service providers to minimise the extent to which they are exposed to excess capacity. [114]

However, calculating a reference tariff based on forecast demand encourages developers to size pipelines so that market growth can be accommodated. This counters recent suggestions that the regulatory framework is forcing the development of purpose-built pipelines with no spare capacity and is deterring efficient investment.

NERA's preferred option is for tariffs to be set on the basis of defined capacity, irrespective of the level of actual volumes. However, the approach adopted by Australian regulators in setting reference tariffs mitigates the risks faced by service providers should volumes decrease. If a service provider forecasts a decline in demand, price caps would increase to ensure that the service provider has the opportunity to earn the required amount of revenue.

In Australia, the service provider has a clear incentive to understate forecast demand in order to achieve a higher reference tariff. This potentially enables the service provider to earn revenue in excess of the regulatory revenue requirement. Given this incentive to understate demand forecasts, they must be assessed for reasonableness and vetted by due consultation with users. To date the ACCC has carefully assessed forecasts but has generally found the forecasts proposed by service providers to be acceptable.

4.3 Balancing objectives under the Code

The Code requires the ACCC to weight and balance objectives in determining reference tariffs. This task has been assisted by the recent Epic court decision in Western Australia and will be further facilitated by the MAPS and GasNet Tribunal decisions. The ACCC has sought to get the balance right and as mentioned previously has tended to be conservative, to the benefit of service providers, in its approach. In addition, the incentive properties of the building block approach also provide the pipeline with an opportunity to earn extra revenue.

Specifically, section 8.1 of the Code requires reference tariffs to achieve a range of objectives, amongst these is section 8.1(b), 'replicating the outcome of a competitive market'.[115] This section was considered in the Epic decision in Western Australia. In that decision the court interpreted 'competitive market' to be a 'workably competitive market'. The court's interpretation of section 8.1(b) has been the subject of considerable discussion and further debate (Attachment 1 considers this in more detail).

The Epic decision appears to conclude that a 'competitive market' excludes the theoretical concept of 'perfect competition' in preference to 'workable competition'. In relation to facilities with natural monopoly characteristics this implies that regulation should produce outcomes consistent with effective competition, more specifically it should produce acceptable outcomes.

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[114] NERA (October 2000) *Regulation Of Tariffs For Gas Transportation In A Case Of 'Competing' Pipelines: Evaluation Of Five Scenarios*, p. 23.

[115] s.8.1, Code.

4.4 Emerging trends in access regulation

Since the commencement of the Code, all parties affected by the regulatory framework have developed an enhanced understanding of its operation and application. As a consequence, a greater understanding of access pricing principles under the Code has stimulated a growing debate amongst governments, industry and regulators regarding options for reforming existing access pricing methodologies.

The review of the National Access Regime

The Productivity Commission released its final report into the National Access Regime in September 2001 with the Commonwealth Government issuing its interim response to that report in September 2002. The Commonwealth proposed to broaden several of the Productivity Commission's recommendations through proposing that pricing principles in Part IIIA to provide incentives to reduce costs or improve productivity.[116]

The Productivity Commission recommended that CoAG initiate a process to develop productivity measurement and benchmarking techniques necessary for regulators to make greater use of productivity-based approaches to setting prices.[117] The Commonwealth was of the view that given the issues involved were highly technical and would require expert analysis, it would be more appropriate to consider those as part of investigations into industry specific regimes.[118]

The Parer Report

More recently, and in addition to the Productivity Commission's review of the National Access Regime, CoAG's Parer Panel reported on the operation of the energy market. In its final report, it suggested that the form of economic regulation be given further consideration, specifically:

> … the future debate would be most effective if it focussed on moving regulation to a less intrusive form. This may best be brought about by giving further consideration to regulators relying on industry wide rather than detailed company specific information.[119]

The Parer report largely focussed on high level issues and did not investigate or make specific recommendations with regard to alternatives to present pricing models practices.

Utility Regulators' Forum

In addition to the recommendations of government reviews and the Commonwealth's position on refining access pricing principles, these issues have also been given consideration by the Utility Regulators' Forum (URF). Matters relating to incentive regulation, benchmarking and utility performance were the subject of a URF discussion

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116 Commonwealth Government (September 2002), *Government Response to the Productivity Commission Report on the Review of the National Access Regime*, Government Response to Recommendation 6.3, p. 4.

117 Productivity Commission (September 2001), *Part IIIA*, Recommendation 12.2, p.351.

118 Commonwealth Government (September 2002), *Government Response to Part IIIA*, Government Response to Recommendation 12.2, p. 17.

119 Parer Review (2002), p. 81.

paper, in November 2000.[120] After the release of the discussion paper the URF commissioned a consultancy into index and productivity-based pricing. In response, a draft consultancy report prepared by Farrier Swier was released in May 2002 and a final version in June of that year.[121]

In September 2002, the URF released a discussion paper inviting comment on the Farrier Swier report with the intent of engaging interested parties in a discussion about pricing options for regulated networks.[122] In May 2003, the URF invited interested parties to participate in, and attend, a one day seminar on the issue of total factor productivity-based pricing.

The debate on access pricing that has emerged does not indicate a clear view on which is the preferred approach. A range of options have been put forward, some of which are outlined below.

Total factor productivity

Total factor productivity (TFP) is a non statistical productivity growth measure that accounts for all factors of production, which primarily include capital, energy, raw materials and labour.[123] TFP techniques set "X" directly based on historical analysis of a TFP index. TFP techniques involve the definition and measurement of the agreed productivity basket index over an appropriate period.[124]

Critical to the effectiveness of the TFP analysis is the collection, measurement and interpretation of data to determine an appropriate "X". The TFP approach does require that the initial price (or revenue) be set through some method which could be rate of return, building block or some other method.

TFP approaches based on building blocks and benchmarking

The TFP approach entails using the building block method to determine the initial access price (P_0) and then adjusting this utilising a "X" factor. [125] Price adjustments could also be accompanied by a mechanism to distribute the benefits of superior performance to both the service provider and third parties. This option could also include provision for regular regulatory reset and would be accompanied by off-ramps to be activated under prescribed circumstances An alternative to this approach is a TFP-benchmarking hybrid approach that entails setting a P_0 based upon benchmarking of other costs to determine an appropriate initial access price. In addition this model would incorporate the other features of the option referred to above.

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120 ACCC (Robert Albon) (November 2000), *Incentive regulation, benchmarking and utility performance*: Utility Regulators' Forum, discussion paper.

121 Farrier Swier Consulting (May, June 2002), (Draft, Final) *Comparison of Building blocks and Index-based approaches*.

122 ACCC (Sept. 2002), *Media release: Utility Regulators' Forum Reports on Network Access Regulation*.

123 Farrier Swier Consulting (June, 2002), p. 31

124 Farrier Swier Consulting (June, 2002), p. 31

125 Farrier Swier Consulting (June, 2002), p. 37

Farrier Swier approach

Under this option price could be set by establishing an initial P_0 adjusted by a TFP-based index "X" factor, with inclusion of a pass-through mechanism.[126] This approach would be underpinned by an initial fixed regulatory period, with scope to increase the timeframe at subsequent regulatory resets. To complement an increased length in the regulatory period, off-ramps would be activated if a specific trigger event occurred. In addition, the pricing or revenue framework, could incorporate an earnings sharing mechanism.

As mentioned previously these are a range of options and are not an exhaustive list of possible options that could be implemented. The pricing options that have emerged are an attempt to move further away from reliance on those remaining elements of firm specific data that are used, at this point, in the determination of reference tariffs.

Evolution of the regulatory approach

In the initial round of access arrangements it has been necessary to undertake comprehensive assessments of pipeline operators' costs and revenue forecasts owing to the absence of information about appropriate prices. However, the ACCC envisages that subsequent assessments will be increasingly less intensive especially as key issues such as the initial capital base are resolved in the first access arrangement.

The ACCC and other regulators are making greater use of benchmarks to establish efficient operating costs to enhance the incentives provided. The ACCC recognises that the most appropriate form of regulation will evolve with the industry as it matures and the existing level of flexibility contained within the Code will permit such an approach.

There are a number of issues that may impact on the feasibility of a benchmarking approach in the future including limited productivity data and the ongoing potential for variation in productivity growth between individual companies. As benchmarking moves away from a firms own costs there is greater potential for a firm to earn excessive profits or to have insufficient revenue to meet its cost obligations. Either outcome could lead to undesirable outcomes.

[126] Farrier Swier Consulting (June 2002), p. 85

Chapter 5 The Gas Code and market development

Significant concern has been expressed about the capacity of the Code to recognise issues specific to greenfields investment as opposed to established operations. The ACCC accepts this concern and has explored the issues surrounding new investment in some depth. The ACCC has developed strategies to allow service providers to benefit from the upside potential of their investment while still recognising the interests of users. This Chapter examines regulatory issues relating to new or 'greenfields' pipelines.

The Gas pipeline industry has heavily criticised the capacity of the existing gas regulatory regime to accommodate market developments, especially the development of new pipelines. This criticism has led the Productivity Commission and the Parer Review to consider new measures to facilitate investment.

The Productivity Commission's Part IIIA review argued for measures to facilitate investment in new infrastructure on the basis that 'imperfect' access regulation has the potential to deter investment and is manifest by:

> The inevitable regulatory discretion involved in the implementation of access regulation, constraints on service providers' capacity to respond to changes in the market environment and perceptions that regulatory decisions will tend to be biased in favour of users …
>
> … the possibility of earning above normal profits if a project proves to be successful will often be factored into an investment decision to balance the possibility of losses in the event that the project fails. Thus, if there is an expectation that access regulators, in seeking to curb monopoly rents, will also remove or reduce upside profits, some new infrastructure investments are likely to be deferred or permanently deterred.[127]

The Parer Review was concerned with the current regulatory regime and its impact on future investments:

> The preceding discussion deals primarily with existing pipelines. What is important for the future development of competitive markets, however, is whether the current regulatory arrangements have the potential to adversely impact on future investments.[128]

However, the evidence presented in Chapter 1 strongly supports the view that the Code has not been deterring investment. Rather, the evidence is more consistent with the view that the Code has actively facilitated investments.

5.1 Applying the Code to greenfields investment

The ACCC is of the view that the Code in its present form has the capacity to support greenfields investment so that the interests of all parties are balanced. The Draft Greenfields Guideline for Natural Gas Transmission Pipelines (DGG) sets out in detail the elements of the Code that are relevant to greenfields investment and the ACCC has been prepared to provide additional guidance to prospective developers.

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127 Productivity Commission (2001), *Part IIIA*, p. 279.
128 Parer Review (2003), p. 193.

The Parer Review having considered the DGG, observed that:

> The ACCC provided a copy of its Draft Greenfields Guideline paper to the Review. This Guideline highlights the flexibility of the current Gas Code and provides an indication of the ACCC's interpretation of some of the key provisions of the Gas Code.[129]

The Code does not automatically regulate all new pipelines and regulation takes effect only if the developer voluntarily submits an access arrangement, is subject to a competitive tender or if a third party makes a successful application to the NCC for coverage under the Code. The appropriateness of the coverage stage ensures that regulation is only imposed on pipelines that exhibit natural monopoly characteristics and have an opportunity to exercise market power in a dependent market.

The ACCC acknowledges that prospective greenfields pipeline investors may face a different risk profile to an incumbent pipeline operator. As a result, the aim of the DGG is to:

- address the perceptions of risk;
- demonstrate the flexibility of the regulatory framework;
- identify methods for dealing with project-specific risk; and
- assist prospective service providers to evaluate the likely regulatory outcomes for potential or proposed greenfields projects.[130]

The challenge for the ACCC is to assess access proposals to ensure that they establish fair and reasonable conditions for both service providers and users, in a manner that preserves the service provider's economic incentives to fully utilise its assets and develop its business. Accordingly, the ACCC did not intend the DGG to be exhaustive. The responsibility is with the service provider to design an access proposal that best meets its unique needs and circumstances that complies with the principles of the Code.

Risk Profile

The DGG identified in general terms four broad categories of risk faced by greenfields pipeline projects and discussed the treatment of these risks in the regulatory framework.[131] The identified general categories of risk are financial risk, construction risk, operational risk, and demand risk.

Financial risks

The ACCC recognises that in the construction and operational phases, a pipeline development will face financial risks such as those associated with procuring materials in a foreign currency. In order to minimise these risks, a pipeline may use appropriate hedging or swaps arrangements. The regulatory regime recognises these risks. For example, allowing costs incurred in managing financial risk in the construction phase to be capitalised and reflected in the capital base.

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[129] Parer Review (2002), p. 215.
[130] ACCC (2002), *DGG*, p. 4.
[131] ACCC (2002), *DGG*, Ch. 4.

Construction risks

Any construction contract carries risks in the planning and construction phase. For greenfields pipelines subject to the regulatory regime, the Code provides protection by allowing the actual cost of construction to be the initial capital base. There is no scope for regulatory optimisation of new pipelines. This provision, in conjunction with the methodology for deriving tariffs based on forecast volumes and depreciation and price path options, provides significant incentives (and compensation for) configuring pipelines with initial spare capacity and/or scope for expansion to meet future demand.

Operational risks

Operational risks apply to all pipelines and the ACCC recognises that, once established, the operational risk profile of a greenfields pipeline is unlikely to differ materially from an established pipeline. Therefore, such risks should be treated in the same way. That is costs that can be identified and quantified by a service provider, and attributed to specific risk mitigation, can be included in the operations and maintenance costs of the pipeline. Additionally, economic depreciation effectively allows for the carry-forward of losses in the early years of operation, and reference tariffs based on forecast volumes substantially insulate the service provider from volume risks.

Demand risks

The ACCC recognises the inherent uncertainties associated with forecasting demand volumes, likely market growth factors and realisable revenues in relation to greenfields pipelines. The level of demand risk depends upon the extent to which foundation contracts underpin a greenfields project – a new pipeline that is supplying gas to a new or immature market faces greater uncertainty regarding future demand than a pipeline that is fully contracted and supplying gas to a well-established market. To the extent that foundation customers bear some of the risk associated with the throughput of the pipeline it may be appropriate for them to be compensated for this risk through lower tariffs than would apply to other users. Similarly, as throughput increases it may be appropriate for all users to share the benefits if the increased throughput reduces average costs.

Options for mitigating risks

A number of options are available to provide greater certainty to prospective service providers when formulating an access arrangement.

Term of the regulatory period

The Code allows the regulator to consider an access arrangement period of any length. However, where the access arrangement period is greater than five years it requires the regulator to consider whether mechanisms should be included in the access arrangement to address the risk of forecasts on which the terms of an access arrangements were based and approved proving incorrect.[132]

[132] Code 3.18

Demand forecasting

There is likely to be inherent uncertainty for a prospective service provider in forecasting demand volumes and growth profiles beyond its contracted foundation customer base, in immature or undeveloped markets.[133]

While there is an inherent element of subjectivity associated with forecasts the Code provides for appropriate review mechanisms in the event that forecasts diverge significantly from realised outcomes.[134] If this does occur mechanisms are available to ensure that any under recoveries in the early years of a pipelines life can be compensated for in the regulatory framework. Flexibility as to the timing and quantum of the effect of a review mechanism in varying a reference tariff is also provided for under the Code.

While there is a potential incentive for prospective service providers to 'game' their expected demand forecasts, such an approach may result in an adverse outcome for the service provider by lowering of the benefit sharing threshold point. The formal approval process of an access arrangement also requires public consultation that would provide an opportunity for interested parties to comment on the proposed demand forecasts.

Accordingly, an effective framework needs to establish an agreed basis that provides certainty at the outset and incentives for a prospective service provider to maximise the use of its reference service and earn a greater than normal return up to a pre-determined point for a known period. The ACCC considers that the inclusion in an access arrangement of a threshold point from which benefit sharing should occur is desirable.[135]

Appendix 1 of the DGG provides an example for derivation of revenues when expected demand is uncertain with an illustration of a possible demand survey to determine expected returns. The illustration further highlights the role that capacity configuration plays in potential upside benefits and that pipelines with limited expansion options could act to cap the blue sky available from higher demand scenarios.

Benefit sharing mechanisms

The Code recognises that in order to encourage investment, a prospective service provider should be given the opportunity to reap some of the upside or 'blue sky' potential of the pipeline. It also requires regulatory certainty as to the treatment of any greater than normal returns, if realised, in the initial regulatory period/s.[136]

There is a range of benefit sharing mechanisms that a prospective service provider could consider when formulating an access arrangement. A benefit sharing mechanism would involve the inclusion of a methodology for the sharing of greater than expected revenues between the service provider and users, and may also identify an event that will invoke the benefit sharing provisions. The inclusion of such a clause in the access

133 ACCC (2002), *DGG*, Ch. 4.5.
134 Code 3.18
135 In the case of an access arrangement the threshold would need to be formulated in accordance with review mechanisms set out in section 3.18 of the Gas Code.
136 Code 8.44

arrangement would provide the service provider with certainty from the outset, regarding the nature and effect of any benefit sharing and at what point it will commence. Possible trigger events could be based on demand, revenue, profit or a combination of these.[137]

A benefit sharing mechanism would only come into operation after the service provider has been appropriately rewarded for undertaking the investment. The service provider would still continue to receive a financial benefit from any further growth in demand.

Downside risk mitigation

There is often uncertainty surrounding the accuracy of demand forecasts. Provided the forecast information presented to the ACCC is unbiased, there is equal likelihood that the service provider will outperform or under perform its forecasts. To outperform and retain the resulting returns until the end of the access arrangement period may provide the service provider with a substantial increase in the actual rate of return. Conversely, under-performance could result in a significant burden to the business.

Section 2.28 of the Code provides that the service provider may seek revisions to its access arrangement at any time. In contrast, the ACCC cannot initiate an early review.[138] These provisions afford protection to a prospective service provider in the event that unforeseen factors impact on it and constrain its ability to earn a reasonable return. For example, the service provider is able to seek a review of the access arrangement if its demand projections are found to be optimistic.

These provisions in respect of review can bias expected outcomes in favour of the service provider.

Determining the initial capital base

Section 8.12 of the Code provides for the initial capital base (ICB) of a new pipeline to be included at the actual capital cost of the assets at the time they first enter service. There is no scope for regulatory optimisation of new covered pipelines under the Code. This contrasts with the treatment of existing pipelines where the regulator must consider valuations based on methodologies such as depreciated actual cost and depreciated optimised replacement cost.[139]

The ACCC is aware that the costs of a greenfields pipeline may not be known with precision until some time after it commences operation and that initial reference tariffs would need to be determined based on forecast capital and non-capital costs. The ACCC considers that a forecast ICB could be used when determining the initial reference tariff in conjunction with an appropriate mechanism to adjust the tariff when the actual capital cost is known with certainty. Appendix 2 of the DGG sets out an example of an adjustment to the initial capital base to reflect actual costs and the effect on reference tariffs.

137 ACCC (2002), *DGG*, Ch. 6.2, 6.3 and Appendix 3
138 ACCC (2002), *DGG* Ch. 5.3.
139 ACCC (2002), *DGG* Ch. 5.2.

Depreciation

Under the Code a depreciation schedule should reflect the following principles:[140]

- the change in reference tariffs over time is consistent with the efficient growth of the market for the services provided;
- depreciation occurs over the economic life of the asset(s) with progressive adjustments where appropriate to reflect changes in expected economic lives; and
- an asset is depreciated only once and total accumulated depreciation will not exceed the valuation of the asset when initially incorporated in the capital base.

Standard straight line depreciation over the economic life of the asset has typically been the methodology used when depreciating a pipelines capital base. However, provided that the principles of the Code are adhered to, a service provider is able to use an alternative approach that may be more appropriate to its circumstances.[141]

The Central West Pipeline (CWP) access arrangement final decision provided for the use of economic depreciation as part of the service providers NPV/price path methodology to determine total revenue.[142] Thus the CWP could set lower tariffs in the initial stages of the life of the pipeline enabling greater opportunities for market development and also have the opportunity to later recoup under recoveries accrued in the early period of the life of the pipeline.

Foundation contracts

Long-term transportation contracts are often established between service providers and key users prior to the building of a pipeline. These foundation contracts often underpin the pipeline's development and represent a financial commitment to reserve capacity on the pipeline by the user. Long-term firm transportation contracts underpin the development of new gas pipelines by sharing long term 'investment risks' between prospective service providers and shippers.[143]

The contractual arrangements between the service provider and foundation customers are as negotiated by those parties. There is no regulatory intervention into provisions that may be included in any foundation contract.[144] Prudent commercial arrangements for foundation customers might ordinarily include escalation and/or discount provisions that may be driven by factors such as realised growth in volumes, and sharing of the risks, costs and benefits in a developing market.

Contracts in existence prior and subsequent to an access arrangement

The regulatory approval process for a greenfields pipeline access arrangement does not affect the ability of a prospective service provider to contract on negotiated terms with users. For example, under section 2.25 of the Code, contracts in place prior to the approval of an access arrangement are preserved.[145]

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140 Code 8.33
141 ACCC (2002), *DGG*, ch.6.6
142 CWP final decision, 30 June 2000, pp. 68-72.
143 NERA (March 2002), *Foundation Contracts and Greenfields Gas Pipeline Developments*.
144 ACCC (2002), *DGG*, Ch. 5.1.2, 5.1.3.
145 ACCC (2002), *DGG*, Ch. 5.1.2.

The Code does not permit the regulator to deprive a person of pre-existing contractual rights. The only exception is for contractual terms relating to certain exclusivity rights.[146]

5.2 The 'truncation problem'

In the Productivity Commission's review of Part IIIA it raised the concept of 'regulatory truncation' as a significant risk to new investment. This concept has been described by the Productivity Commission, as:

> … once an infrastructure facility is operating successfully, it can be very difficult for access regulators to differentiate between genuine monopoly rent and upside ('blue sky') profits accruing to the facility owner. As discussed in chapter 4, the possibility of earning above normal profits if a project proves to be successful will often be factored into an investment decision to balance the possibility of losses in the event that the project fails. Thus, if there is an expectation that access regulators, in seeking to curb monopoly rents, will also remove or reduce upside profits, some new infrastructure investments are likely to be deferred or permanently deterred.[147]

A project proponent would analyse possible demand scenarios at the stage of project evaluation and arrive at a range of expected rates of return. A positive probability of low returns may be offset by a possibility of high returns. In most proposed projects where the mean expected rate of return (MERoR) is above the project weighted average cost of capital (WACC) the project would probably proceed to implementation.

A 'truncation problem' results where the regulator is able to *ex post* reduce high return scenarios and thereby have an impact on the *ex ante* expected rate of return. If the developer expects high returns to be capped by a regulator then this may reduce the *ex ante* MERoR to a level that renders the project unviable.

Regulation of gas pipelines takes place only where the potential exists for the pipeline operator to exercise market power. The NCC in recommending coverage is required to consider the market power of the pipeline. To the extent that a marginal pipeline has limited market power then it is unlikely to be covered.

Figure 5.1 describes a probability distribution of expected returns of a project where the downside and upside is assumed to be symmetrical. As can be seen the WACC is 6% and below the MERoR of 8%.

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[146] Code 2.25
[147] Productivity Commission (2001), *Part IIIA*, p. 279.

Figure 5.1 Project WACC and MERoR

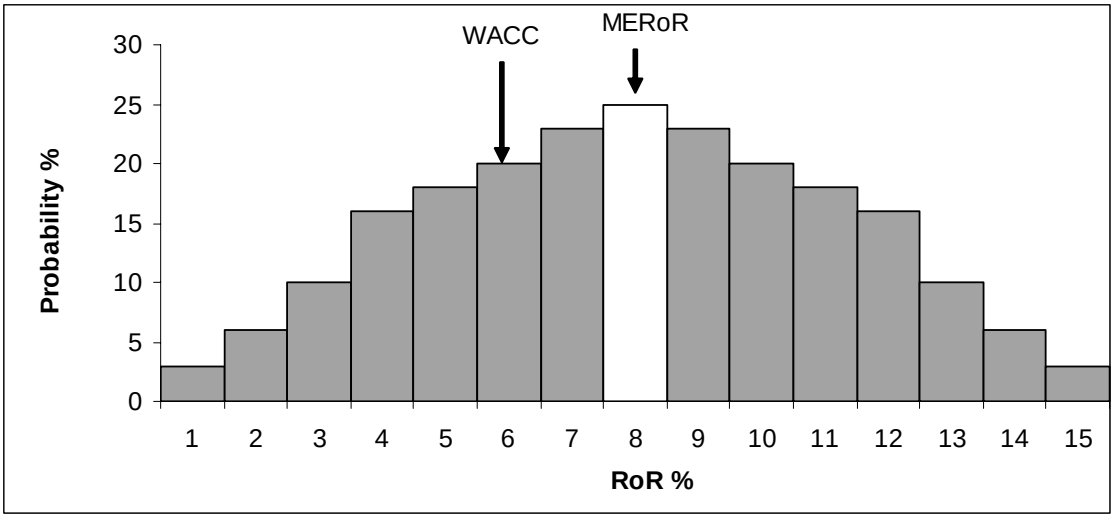
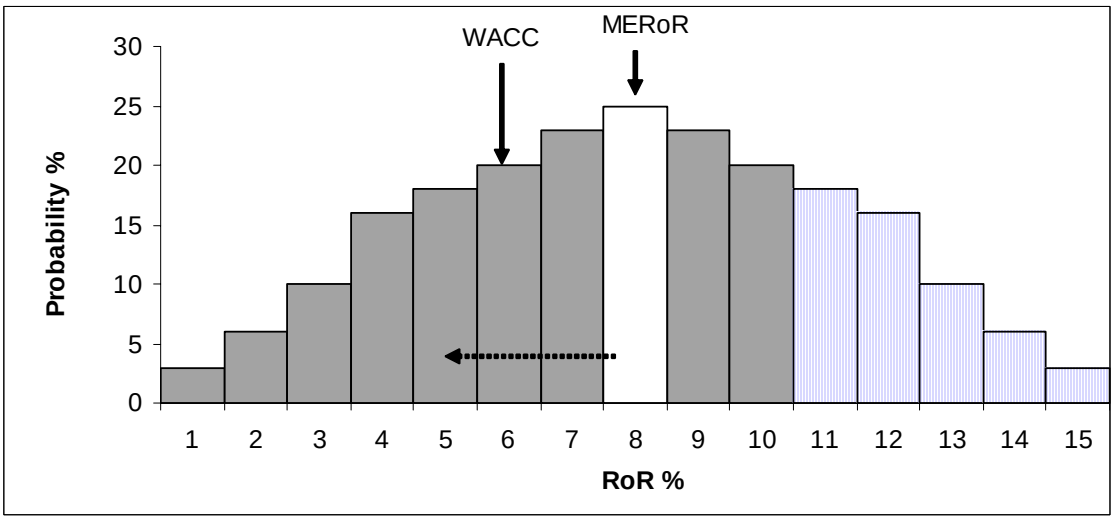


Figure 5.2 shows the probability distribution prior to regulatory truncation of upside returns and the *ex ante* MERoR is 8%. Regulatory truncation is assumed to take effect where the *ex post* observed rate of return is above 10%. If there is an expectation that the regulator would disallow all rates of return above 10% then the *ex ante* MERoR moves to the left of 8%. As shown in Figure 5.2 the post truncation MERoR is 5.5%. Therefore, the project would not be viable as the MERoR is below the WACC.

Figure 5.2 The 'truncation problem'



Upfront coverage opinions

The Code provides a procedure by which a prospective pipeline developer is able to request an advance advisory opinion from the NCC as to whether a prospective pipeline would meet the criteria for coverage.[148] The opinion provided by the NCC in response to a request for an advisory opinion does not have any binding effect on the NCC in relation to any subsequent application for coverage.[149]

[148] Code 1.22
[149] Code 1.23

Regulatory uncertainty is perceived to be prevalent where there is a possibility of the regulator stepping in with better information at a future date as against the information available at the time the investment decision was made. However, an upfront binding coverage opinion could mitigate the regulatory uncertainty as the NCC and the prospective developer would be contemporaneously considering the available information.

The Parer Review concluded that binding upfront coverage rulings would provide additional certainty for pipeline developers and recommended that the Code be amended to allow for the granting of binding coverage rulings for fixed periods of time without the ability to revoke the ruling unless the information relied upon proves to be false or intentionally misleading.[150]

On the period of a binding upfront coverage ruling, the Parer Review stated:

> The ideal period would be the minimum period regulatory certainty was required to deliver an expected return sufficient to make the investment profitable. A period of fifteen years should be sufficient in most situations.[151]

5.3 Mitigating the 'truncation problem'

The ACCC is conscious of the need to provide incentives for long term efficient investment and also mindful that a perception of the 'truncation problem' could impede socially desirable investment.

To resolve some of the concerns associated with the perception of regulatory truncation of blue sky returns, the ACCC has indicated in the DGG that it is receptive to proposals from service providers that mitigate the risk profile of a greenfields pipeline, provided such proposals are consistent with the objectives of the Code.

Upfront regulatory agreements

The ACCC has indicated in the DGG that an upfront regulatory agreement is an appropriate mechanism by which the ACCC is willing to bind its future discretion in order to provide long-term regulatory certainty to investors in gas transmission pipelines.

The Code provides for prospective pipeline developers to enter upfront agreements with the regulator.[152] These upfront agreements are available to give certainty over structural elements in a reference tariff policy and are applicable to both access arrangements under the Code and access undertakings under Part IIIA of the Trade Practices Act.

Upfront regulatory agreements may be given effect through fixed principles that may include any structural element. A fixed principle may not be changed for a specified period without the agreement of the service provider. However, in determining the fixed period regard must be given to the interests of the service provider, users and

150 Parer Review (2002), p. 211.
151 Parer Review (2002), p. 211.
152 Code 8.47 and 8.48

prospective users. In this way a pipeline company seeking certain provisions to be sustained over a long term can do so without necessarily having to propose a long access arrangement duration.

Structural elements specifically include the depreciation schedule; the financing structure; and that part of the rate of return that exceeds the return that could be earned on an asset that does not bear any market risk. These provisions can give investors long-term regulatory certainty over how their investment will be treated. The provisions clarify parameters over which the regulator might otherwise seek to exercise discretion and which could leave investors unclear about future regulatory changes.[153] A market variable element of the reference tariff policy cannot be a fixed principle.

The Parer Review considered the availability of upfront regulatory agreements as a mechanism that afforded long term certainty for prospective pipeline companies and concluded that:

> An alternative to the 15 year price regulation free period for prospective pipeline companies seeking longer term regulatory certainty is to enter into an upfront agreement with the regulator.[154]
>
> In the Panels view, there is considerable scope for pipeline companies to reduce regulatory uncertainty by taking advantage of the provision for up-front regulatory agreements in the Gas Code.[155]

AGL in its submissions to the Productivity Commission review on Part IIIA proposed that:

> One option for investors who require greater certainty *ex ante* would be a requirement for an explicit regulatory contract between the regulator and the regulated firm. The terms of this contract would be agreed upon prior to the regulated firm making an investment in assets that are likely to be subject to regulated access requirements under Part IIIA. Such *ex ante* agreements will allow the regulated firm to undertake more precise financial modelling with a view to making the final decision on whether or not to proceed with the investment.[156]

The Parer Review concluded that an upfront regulatory agreement provides a service provider an opportunity to 'lock in' key regulatory parameters for extended periods of time and can potentially provide regulatory certainty for the life of a pipeline.[157]

> Prior to construction, a pipeline company can approach the regulator with a detailed proposal of the services it intends to offer and reference tariffs for those services. It can seek to 'lock in' for extended periods of time the key regulatory parameters- such as weighted average cost of capital or return on equity, risk factors, depreciation schedules, financing structures or the operation of revenue sharing mechanisms.[158]

The Productivity Commission's Part IIIA report stated that upfront regulatory undertakings would have a number of advantages in that:

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153 ACCC (2002), *DGG*, p. 31.
154 Parer Review (2002), p. 214.
155 Parer Review (2002), p. 215.
156 AGL submission to Productivity Commission, DR 86, pp. 11-12.
157 Parer Review (2002), p. 214.
158 Parer Review (2002), p. 214.

- They would help to reduce regulatory risk facing prospective service providers.
- They would provide assurance to the community that market power expected to attach to proposed infrastructure facilities would not be unreasonably exploited.
- Once the upfront transaction costs involved in securing agreement on the conditions of such an undertaking had been incurred, some ongoing costs of this nature could be avoided.[159]

The Productivity Commission was of the view that an upfront regulatory agreement would not in itself address the regulatory truncation problem, as the degree of truncation would be dependant on the detailed parameters of such an undertaking.[160]

However, the ACCC is of the view that there are several factors that substantially (or entirely) mitigate the possibility of a truncation problem and these aspects of the regulatory regime are discussed below.

Concept of a reference tariff

Gas pipeline regulation is based on the concept of a reference tariff rather than an allowed rate of return. In addition, the reference tariff is calculated based on forecast demand rather than pipeline capacity. Unlike rate of return regulation, where a project has little opportunity of earning rates of return above the regulated rate of return, reference tariff based regulation allows a pipeline company the opportunity of achieving rates of return above its MERoR.

Thus, in Figure 5.1 all potential outcomes to the right of the MERoR are accessible to the pipeline owner – the MERoR does not shift to the left and there is no truncation problem.

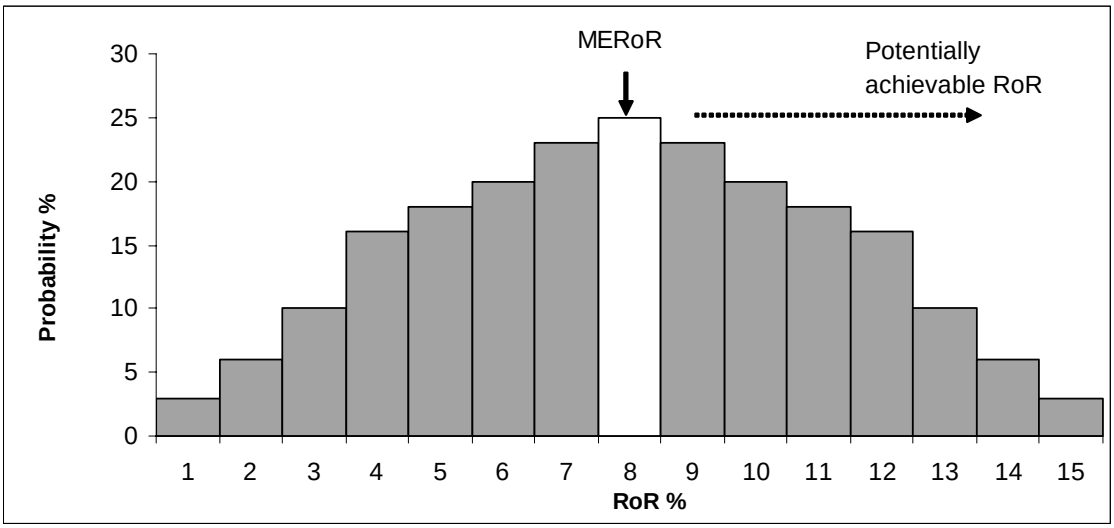
Forecast demand based reference tariff policy

The ACCC is mindful that the regulatory approach under the Code is based on demand forecasts rather than pipeline capacity, allowing the pipeline company to achieve higher rates of return where actual volumes exceed forecasts volumes. The tariff is set to enable the pipeline company to achieve revenues based on demand forecasts that would be sufficient to cover WACC.

Figure 5.3, shows a project with a MERoR of 8% and the rates of return to the right of the MERoR are potentially achievable where the actual volumes exceed the mean forecast volumes. Therefore, the actual rate of return could potentially be higher than the *ex ante* MERoR rate of return. The pipeline company is able to retain the actual returns achieved during the access arrangement period.

[159] Productivity Commission (2001), *Part IIIA*, p. 296.
[160] Productivity Commission (2001), *Part IIIA*, p. 296.

Figure 5.3 Effect of forecast volume based regulation



Asymmetric review

There is often uncertainty surrounding the accuracy of demand forecasts. Provided the forecast information presented to the ACCC is unbiased, there is equal likelihood that the service provider will outperform or under perform its forecasts. To outperform and retain the resulting returns until the end of the access arrangement period may provide the service provider with a substantial increase in the actual rate of return compared to the benchmark. Conversely, under-performance could result in a significant burden to the business.

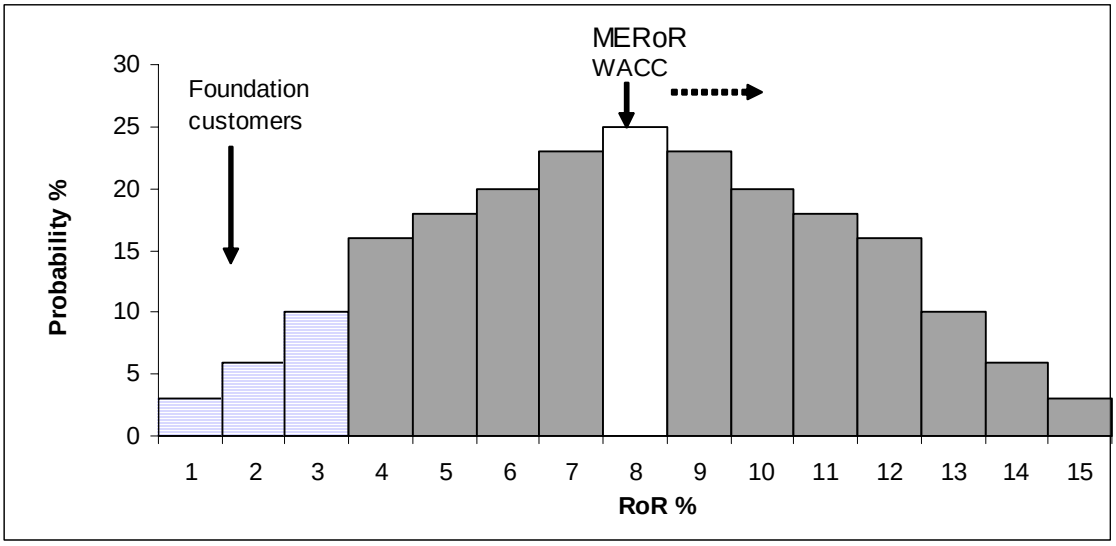
The Code permits service providers to seek review of an access arrangement at any time. However, regulators may not reopen an access arrangement prior to the review date unless a specific trigger event has been incorporated in the access arrangement. These provisions in respect of review asymmetrically bias expected outcomes in favour of the service provider.

Foundation customers

Foundation customers of a new pipeline company mitigate the 'truncation problem' by guaranteeing a minimum level of throughput and revenue. The foundation contracts cap the possible downside risks and increases the *ex ante* expected average rate of return.

Figure 5.4, shows a project prior to foundation contracts where the MERoR is set equal to the WACC at 8% and the project could be described as a marginal project. As can be seen, foundation customers guarantee a 3% minimum rate of return and have the effect of moving the MERoR to the right of 8% to 9.5%.

Figure 5.4 Effect of foundation customers on the MERoR



Carry forward of losses

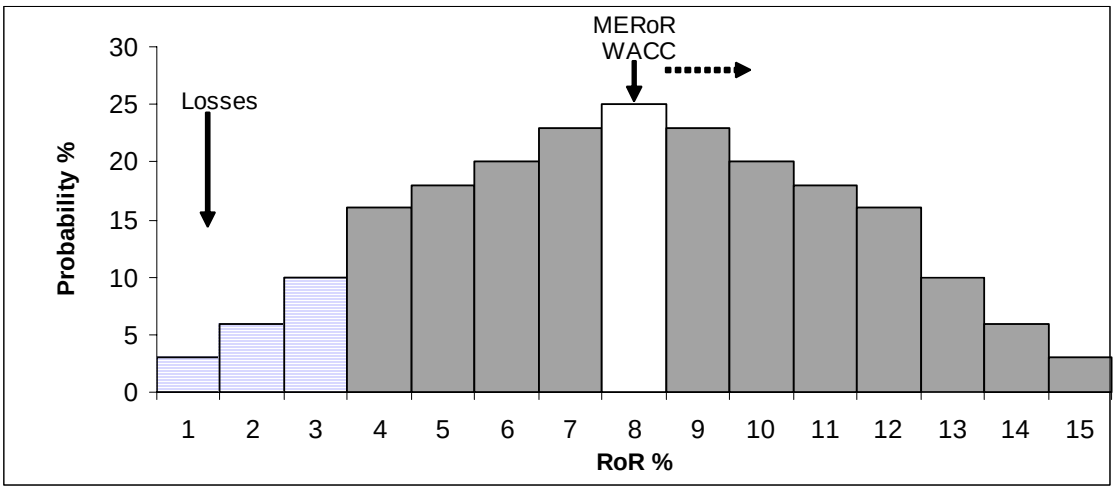
The regulatory framework under the Code allows for the carry forward of losses and the capitalisation of financial losses. This has the effect of providing ex ante certainty as to the regulatory approach to the treatment of potential downside.

> The ACCC considers that the impact of demand risks on regulatory revenue can be mitigated through careful information analysis and the design of the regulatory arrangements. For example, a number of probability weighted demand scenarios could be used to determine an expected demand forecast. An appropriate mechanism could then allow any under recoveries in the early years of an access regime to be subsequently recouped when demand grows.[161]

The carry forward and capitalisation of losses and its effect on the *ex ante* MERoR is illustrated in Figure 5.5. The MERoR is set equal to the WACC and the project could be described as a marginal project. As can be seen, where the downside is removed by the availability of the loss carry forward provisions the *ex ante* MERoR increases similar to the impact that foundation customers have on the MERoR.

[161] ACCC (2002), *DGG*, p. 18.

Figure 5.5 Effect of carry forward of losses



It is possible that a pipeline could have continuous losses and not be in a position to benefit from the loss carry forward and capitalisation provisions of the Code. A continuously loss making project would probably have been an *ex ante* marginal project and would require a closer evaluation of the investment decision.

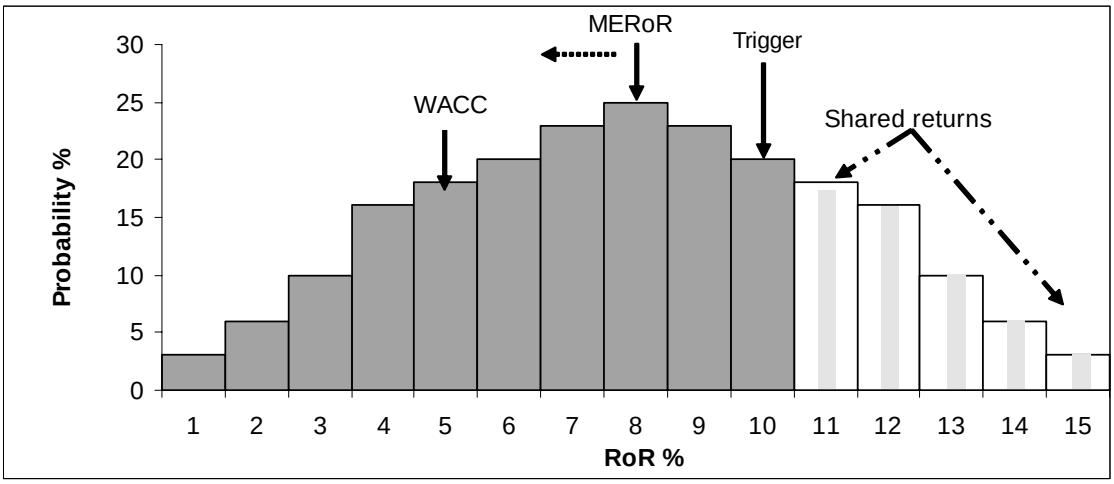
Benefit sharing mechanism

The benefit sharing mechanism as proposed by the ACCC in the DGG counters the deterrent effect that the 'truncation problem' is perceived to have on investment by an *ex ante* agreement to share revenues resulting from greater than expected demand. For pipelines that have the potential to exercise market power, a benefit sharing mechanism can be incorporated in the access arrangement that would share profits between users and the pipeline developer in high return situations.

Depending on the amount of sharing, the service provider has *ex ante* certainty as to the *ex post* regulatory effect on actual returns which are higher than the MERoR thus negating the 'truncation problem.'

The effect of a benefit sharing mechanism is illustrated in figure 5.6. The trigger for the benefit sharing mechanism is assumed to be when returns are above 10%. Therefore as shown in Figure 5.6, a pre agreed percentage of the returns above 10% would not be available to the pipeline developer. The benefit sharing mechanism does result in the MERoR moving to the left of the *ex ante* MERoR. However, the amount of sharing above 10% would be *ex ante* known to the pipeline developer and the ACCC is mindful of the need to allow a MERoR equal to or above the project WACC.

Figure 5.6 Effect of a benefit sharing mechanism



Competitive tenders

The Code provides for a tender process in relation to a pipeline that has not been built to determine:

- Reference tariffs for certain reference services to be provided by means of the proposed pipeline;
- Other specified items which are required to be included in an access arrangement and which are directly relevant to the determination of the reference tariffs concerned.[162]

The competitive tender process is available to prospective pipeline developers as an alternative to setting tariffs according to the principles set out in section 8 of the Code. It is anticipated that the competitive pressures between bidders for the development rights of the proposed pipeline will produce tariffs that achieve the objectives of the Code.

The tender process allows the competitive bidding process to set the parameters of the reference tariffs of the initial access arrangement period and precludes the regulator from carrying out analysis of costs, returns or tariffs. This mechanism allows for a degree of certainty to prospective pipeline developers and investors as the parameters are set by market forces and the perceived regulatory risk associated with the regulator's discretion in applying reference tariff parameters is mitigated.

In a competitive tender the regulator approves the overall tender process rather than the individual tariff and non tariff elements and once the outcome has been approved in accordance with the final approval request process the winning bidder becomes the service provider.

Competitive tenders are not appropriate for all new pipeline developments in all circumstances. When considering a request to conduct a tender the ACCC will take into account the general level of interest in the project as well as the number and competitiveness of tenders received in respect of new areas with similar customer

[162] Code 3.21

numbers, load, and geographic and cost profiles.[163] The inherent commercial viability of the proposed project would undoubtedly have a significant role in 'the number and character' of the tenders received as well as the general level of interest in the project.

5.4 Economic regulation free period

The introduction of a regulatory holiday has been canvassed as a method of addressing the potential regulatory risk associated with high risk greenfields projects. A 'regulatory holiday' (or 'access holiday') is a period in which a service is not subject to regulation.[164]

The Parer Review recognised the need to balance two competing objectives in recommending a 15 year price regulation free period. The two objectives are, on the one hand the need for providing greater certainty to pipeline companies, and on the other the need for regulation not to be excluded too far into the future.[165]

The Parer Review stated:

> The risk of a new pipeline being regulated, however, can create significant uncertainty – potentially sufficient to make otherwise marginally profitable proposed pipelines unprofitable and hence not proceed.
>
> In the Panel's view, the solution is that prospective transmission pipeline companies should have the ability to choose not to have any price regulation imposed upon the new pipeline for the first fifteen years of its operation.[166]

In comparison to a 15 year economic regulation free period, an upfront regulatory agreement could provide *ex ante* certainty to greenfields investments as to the regulatory framework applicable to it in 15 years. A prospective service provider may prefer an upfront regulatory agreement to a regulatory holiday as key regulatory parameters could be agreed upon prior to the construction of the pipeline.

The Code requires the regulator to adjust the cost of the initial capital base of a new pipeline if the period between the time a new pipeline first enters service and the time the reference tariff is proposed under the Code is such as to reasonably warrant an adjustment.[167] Therefore, a 15 year economic regulation free period could create uncertainty for the pipeline developer as to the regulatory approach in establishing the initial capital base at the end of the economic regulation free period.

Further, during the period of a regulatory holiday the pipeline company would not have the benefits of the non tariff elements of an access arrangement such as a dispute resolution mechanism which could be considered to be more cost beneficial than litigation.

In recommending the 15 year economic regulation free period, the Parer Review reasoned that:

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163 ACCC (2002), *Regional development of natural gas*, p. 14.
164 ACCC (2002) S*upplementary submission to Parer Review*, p. 13.
165 Parer Review (2002), p. 214.
166 Parer Review (2002), p. 212.
167 Code 8.13

> Investors generally look for an early return on their investments-typically within a seven or eight year period. Gas pipelines are usually longer term investments, with slower payback periods. However as the length of the time increases so does the uncertainty about the economic potential of the project due to resource and market risk.[168]

Therefore, it is expected that a 15 year economic regulation free period would allow a pipeline company the freedom to set tariffs at a rate that would enable it to earn potential blue sky returns in order to offset *ex ante* probabilities of black sky scenarios. However, a new pipeline may not have the ability to achieve higher returns in the early stages of the project as envisaged by an economic regulation free period.

AGL in its submission to the Productivity Commission was of the view that:

> We do not think an access holiday provides the answer for investors concerned about regulatory risk. Any holiday that would remove the risk that the returns for successful projects maybe truncated by regulatory intervention would have to occur towards the end of the project, not at the beginning of the project (when returns are below the cost of capital.)[169]

The 15 year economic regulation free period recommended by the Parer Review was subject to conditions which recognised the need for some aspects of the pipeline company to be regulated. The Parer Review recommended that:

> The Pipeline must:
> - be a new transmission pipeline (i.e. not constructed yet)
> - have sufficient vertical separation of ownership (i.e. no upstream or downstream firm has sufficient ownership to exert control over the pipeline in a way that might lessen competition in upstream or downstream markets)
> - publish tariffs for access to the pipeline
> - provide for full capacity to be fully tradeable.[170]

The issue of a permanent access holiday was raised in the Productivity Commission Part IIIA review and the Productivity Commission after considering the submissions, stated:

> In the Commissions view, permanent exemptions from Part IIIA (or other access regimes) would not be appropriate. This is despite the fact that, for risky marginal projects, a permanent exemption would be required to address the regulatory truncation problem fully. However, permanent exemptions could have unwanted side effects. For example, if they were only available for investments to provide new services they could encourage excessive maintenance to extend the life of exempt facilities. Also, the possibility of inefficient pull forward of investment may be somewhat greater with permanent exemptions than with conditional or temporary exemptions. Like very high regulated rates of return, perpetual exemptions could also create considerable disquiet among users and the wider community, possibly making them difficult to sustain.[171]

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168 Parer Review (2002), p. 213.
169 AGL submission to Productivity Commission, DR 86, p. 11.
170 Parer Review (2002), p. 213.
171 Productivity Commission (2001), *Part IIIA*, p. 307.

Chapter 6 Costs and benefits of regulation

Regulation is a second best alternative that is never perfect or costless. Alternatively, in the presence of natural monopoly and market power, the absence of regulation can impose significant costs on the economy. Consequently, it is necessary to undertake an empirical cost benefit analysis to determine whether regulation is generating better outcomes than would be achieved in its absence.

6.1 A cost-benefit analysis framework

As set out by the Productivity Commission, any decision on whether to apply regulation should be based around a cost-benefit analysis.

> Even if a regulation will have benefits, intervention will only be warranted if those benefits exceed the regulatory costs.[172]

The following discussion draws from a wide range of material in order to identify the items that would be relevant to such an analysis.

The costs of natural monopoly in gas

The writers of the Code were conscious of the negative consequences arising from the abuse of monopoly power and explicitly aimed to prevent those outcomes.

> The objective of this Code is to establish a framework for third party access to gas pipelines that:
> …
> (b) prevents abuse of monopoly power; and
> …[173]

The profit maximising behaviour of gas firms that possess market power will lead to a range of adverse effects. Some of the major costs of monopoly behaviour were set out in general terms in the Productivity Commission's Part IIIA review as follows:

> … in the absence of regulation, denial of access to essential infrastructure services, or monopoly pricing of access, would be more than an isolated occurrence. As well as detracting from the efficient use of the services concerned, such behaviour would also compromise efficient investment in related markets. Moreover, the pursuit of monopoly rents might also have adverse consequences for the timing of investment to provide new essential services and to augment existing networks.[174]

Throughout the Productivity Commission's Review of Part IIIA a range of negative consequences arising from the exercise of market power were identified. The key elements were summarised in Box 2.1 and included income re-distribution, higher prices, sub-optimal usage, income transfers, reduced competitiveness in downstream markets, reduced quality and reliability, distortions in investment decisions and lack of innovation. These adverse affects are examined in more detail in the following sections.

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172 Productivity Commission (2001), *Part IIIA*, p. 59.
173 Gas Code, Preamble.
174 Productivity Commission (2001), *Part IIIA*, p. 53.

Denial of access

In recent times, the gas pipeline sector has arguably witnessed an example where access has been denied (or offered on unacceptable terms) being the Horsely Park duplication. This example demonstrates that in the absence of access regulation the denial of access to gas transport facilities must be considered as a significant probability. Such denial of access may lead to reduced competition in related markets or socially wasteful duplication of assets.

Monopoly pricing

The adverse impacts arising from monopoly pricing are well recognised. Concerns about these effects were a significant factor in the Hilmer Review:

> In markets characterised by workable competition, charging prices above long-run average full costs will not be possible over a sustained period, as above-commercial returns will attract new market participants or lead consumers to choose a rival supplier or substitute product. Where the conditions for effective competition are absent – such as where a firm has a legislated monopoly or the market is otherwise poorly contestable – firms may be able to charge prices above efficient levels for periods beyond a time when a competitive response might reasonably be expected. Such 'monopoly pricing' is detrimental to consumers and to the community as a whole. Nothing in the TPA addresses this issue, and the Prices Surveillance Act has significant limits on its reach.[175]

While it is difficult to establish the quantum of monopoly pricing that would arise in the absence of access regulation, some insights might be drawn from the material presented in Chapter 1. Table 1.1 shows the initial prices sought by service providers compared to the final prices permitted by the ACCC for each regulated transmission pipeline. These results need to be interpreted with caution as it is impossible to determine the counterfactual, however, they do suggest that pipeline operators desire the option to raise prices significantly above those permitted under the regulatory regime.

This analysis could be extended to examine the divergence between requested prices and regulated prices for each distribution system.

Elasticity of demand

The elasticity of demand for gas may also provide an indication of the propensity for monopoly pricing in the industry. To the extent that demand for gas is inelastic then service providers are likely to find monopoly pricing profitable as customers are less likely to switch to other energy sources. The magnitude of the reduction in gas consumed would depend on the size of the price increase.

Evidence on the magnitude of the elasticity of demand is limited and significant care needs to be employed when drawing conclusions. The elasticity of demand for gas has been considered in some detail in the NCC decision on the MSP. The NCC's key findings include:[176]

- Historically, the demand for gas transport services has been relatively inelastic in the manufacturing and commercial sectors.

[175] Hilmer Report (1993), p. 186.
[176] NCC (2002), *MSP coverage decision*, paras 4.145 to 4.151 and 7.419 to 7.435.

- The most recent information available was prepared by ABARE based on data for the period 1973-74 to 1993-94. Estimated own-price elasticities were: residential -0.78; commercial -0.10; industrial -0.30; weighted average -0.31.
- The elasticity of demand for gas sold to intermediate markets (such as electricity generation) may be higher than the ABARE estimates. A small change in the price of gas could make a proposed generator vulnerable to displacement.

The relatively inelastic nature of demand for gas suggests that where a firm has market power it would be profitable for the firm to raise prices as its customers are likely to be reluctant to switch to alternative energy sources. This argument was reflected in the NCC's MSP decision:

> The Council considers that demand for gas pipeline services is likely to be relatively inelastic, and that this creates incentives for monopoly pricing on the MSP. These incentives are likely to be more potent given the potential for the MSP to expropriate a share of upstream rents from the Cooper Basin producers.[177]

However, as observed by the NCC 'the firm-specific demand for a particular pipeline's services may be less inelastic'.[178] One example provided by the NCC was the energy costs faced by Incitec:

> 7.427 Gas represents 45% of Incitec's total manufacturing cost and 80% of variable cost for the company's Newcastle plant. Further, Incitec informs the Council that transmission pipeline charges represent about 15% of delivered gas costs.[179]

The Parer Review also examined the relationship between energy costs and profitability in key industries. The following table from the Parer Review demonstrates the significance of electricity prices in the cost structures of major Australian industries and the impact a 10 per cent reduction in price can have on profitability.

Table 6.1 Effect of electricity price reductions on profitability[180]

Industry	Energy Costs as a proportion of production costs	EBIT	Effect of 10 per cent margin reduction in energy prices on EBIT margin
Aluminium Smelting	20%	14%	+ 12%
Paper Manufacturing	20%	9%	+ 20%
Chlor/Alkali Production	20%	15%	+ 11%
Brick Manufacturing	18%	10%	+ 16%
Steel Production	11%	14%	+ 7%
Nickel Production	10%	17%	+ 5%
Copper / Uranium Production	10%	8%	+ 12%
Gold Production	8%	7%	+ 11%
Cement Production	7%	8%	+ 8%

177 NCC (2002), *MSP*, para. 7.119.
178 NCC (2002), *MSP*, para. 7.114.
179 NCC (2002), *MSP*, para. 7.427.
180 Parer Review (2002), p. 65.

Sharing rents along the supply chain

The value of regulation of transmission and distribution has been questioned on the basis that any rents removed from the intermediate sector will be captured in the upstream or downstream segment of the industry and final users will be no better off. This argument is essentially a coverage issue and was addressed by the NCC in its MSP decision as follows:

> 1.46 If lower tariffs result in lower delivered gas prices, the demand for gas will rise, especially among customers with relatively elastic demand. Higher levels of demand would stimulate higher rates of production, creating incentives for new entry in the upstream market to satisfy that demand. This change in the competitive environment, flowing from coverage, would satisfy criterion (a).
>
> 1.47 If upstream producers have sufficient market power to expropriate the benefits of lower transport prices, the prospect of increased returns will encourage new entry in the upstream market. The threat or event of new entry, in turn, would promote rivalrous behaviour in that market. Indeed, the reduction in impediments to entry could stimulate more competitive behaviour among incumbent firms as the enhanced threat of entry forces the incumbents to act more competitively on all dimensions that matter to consumers, which includes price, conditions of sale and service. Once again, this change in the competitive environment, flowing from coverage, would satisfy criterion (a).[181]

Equally, competition in downstream segments will be encouraged.

Investment

The impact of access regulation on investment has been the subject of extensive debate in recent times. Largely this debate has focussed on the extent to which access regulation may have deterred efficient investment. However, there is credible evidence that access regulation has facilitated efficient investment that would not otherwise have taken place. In addition, in the context of the gas transport sector the weight of evidence is strongly against the claims made by the pipeline industry that regulation has been deterring efficient investment.

The topic of investment is explored in substantial detail in Chapter 5 of this submission. The ACCC notes that a significant volume of factual evidence is available on this topic and it is therefore not necessary to accept statements on face value.

Dynamic efficiency

Previously, there has been mixed views expressed on the impact of access regulation on dynamic efficiency. For example, in the Part IIIA Review the Productivity Commission stated:

> Apart from lower prices and increased use of services, the provision of access can be an important stimulus to innovation and other so-called ‘dynamic efficiency’ gains. The explosion of product offerings in the telecommunications market in recent years highlights the role that new entrants can play in this regard.[182]

By contrast

[181] NCC (2002), *MSP*, paras. 1.45 to 1.47.
[182] Productivity Commission (2001), *Part IIIA*, p. xviii.

> Even more forcefully, the Law Council of Australia contended:
> Third party access regulation is a very intrusive form of regulation. It may have a serious impact on the dynamic efficiency of an industry, because it lessens the incentive to innovate and invest, and permits free riding on existing infrastructure.[183]

When assessing the impact of gas access regulation on dynamic efficiency, some guidance may be provided by observing the level of investment in the industry and the extent to which the gas market is maturing. In this context, the Parer Review stated:

> These are all encouraging signs of a market that is developing. In this context, the Panel believes that while there have been strong concerns raised regarding the current arrangements in gas, the market is developing and becoming more competitive, dynamic and efficient.[184]

Upstream competition

One of the key objectives of the Code is to promote competition in upstream and downstream markets. Indeed, this is one of the criteria that must be satisfied in order to warrant coverage.

There are concerns that market power in the transmission sector may impede investment and competition in the upstream sector. For example, the Productivity Commission stated:

> Whichever way market power was manifested, output of the final service would, in most cases, be lower than desirable, resulting in an economic loss for the community. Over the longer term, excessive prices for essential infrastructure services could impede investment in downstream (and upstream) markets.[185]

Recent evidence suggests that the Code has facilitated upstream competition. For example, the Parer Review concluded that:

> The recent gas reforms have been effective. By facilitating access to pipelines, and removing the previous restrictions on interstate trade in gas, new pipelines have and are being built, new fields have been discovered, and some initial upstream gas competition has been introduced.[186]

and

> Open access to transmission and distribution infrastructure has played a significant role in increasing upstream competition particularly in the South East Australian markets.[187]

A specific example where upstream competition has been evident is the Queensland Government selection process for conversion of the Townsville power station. In the case of the Townsville power station:

> … Mr Beattie said Enertrade was the preferred developer for a new pipeline sourcing coal seam methane from the Bowen Basin, plus a base-load gasfired power station at Yabulu, near Townsville.

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183 Productivity Commission (2001), *Part IIIA*, p. 4.
184 Parer Review (2002), p. 190.
185 Productivity Commission (2001), *Part IIIA*, p. xviii.
186 Parer Review (2002), p. 35.
187 Parer Review (2002), p. 198.

> … "Eighteen bids were received from ten different bidders as part of the Townsville Power Station process.
>
> "The successful bid was chosen after a rigorous evaluation process because it best met the Government's key criteria including reliability of supply within set timeframes and best value for money."[188]

Downstream competition

Many of the issues identified in the context of upstream competition are also relevant when considering downstream competition. For example, in its MSP decision, the NCC stated:

> 1.52 The Council has found that while competition is emerging in downstream gas sales markets, those markets are not yet sufficiently competitive to constrain MSP pricing. The ACCC and NERA analysis reinforce this finding.
>
> … 1.54 If lower transport tariffs result in lower delivered gas prices, the demand for gas will rise, especially among customers with relatively elastic demand. Higher levels of demand create incentives for new entrants to invest in downstream gas sales markets to satisfy that demand, thus promoting a more competitive environment in those markets. This change in the competitive environment, flowing from coverage, would satisfy criterion (a).
>
> 1.55 Alternatively, if downstream gas sellers have sufficient market power to expropriate the benefits of lower transport prices, the prospect of increased returns in gas sales markets will encourage new entry. The threat or event of new entry, in turn, would promote rivalrous behaviour in those markets. Indeed, the reduction in impediments to entry could stimulate competition among incumbent firms as the enhanced threat of entry forces the incumbents to act more competitively on all dimensions that matter to consumers, which includes price, conditions of sale and service. Once again, this change in the competitive environment, flowing from coverage, would satisfy criterion (a). Over time, rivalrous behaviour between new entrants and incumbents is likely to compete away downstream rents, such that delivered gas prices will fall.[189]

In addition, it is necessary to examine flow-on effects in downstream markets:

> As the National Farmers Federation (NFF) commented:
> Any monopoly rents levied by infrastructure owners represent a form of taxation of intermediate inputs to production or of consumers. For example, inflated electricity or gas network charges feed into the costs of energy users (eg. irrigators and rural processing industries) thereby reducing their competitiveness, and distort production and consumption patterns. (sub. 26, p. 6)
>
> In effect, the sort of welfare costs depicted in the simple diagram in box 3.3 as arising in the market for the final infrastructure service may flow-on to a range of downstream markets for goods and services.[190]

Information

There are a number of dimensions to the information issue that may impact on the cost-benefit analysis.

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188 Beattie, Peter and Terry Mackenroth (4 June 2002), *$500M project to power north and central Queensland*, Media Release.

189 NCC (2002), *MSP*, paras. 1.52 to 1.55.

190 Productivity Commission (2001), *Part IIIA*, p. 48.

First, in the Part IIIA Review the Productivity Commission was conscious that regulators face information asymmetry problems and reliance on imperfect information may lead to error in the regulatory process.

> In framing its recommendations to improve the national access regime, the Commission has had particular regard to the significant information problems confronting access regulators, and the imperfect regulatory instruments at their disposal. There are significant constraints on what even the best resourced and well intentioned regulator can achieve.[191]

and

> Also, regulators are often operating with highly imperfect information, meaning that the spectre of regulatory failure looms large.[192]

However, it is not only regulators that lack adequate information. Service providers themselves face information deficiencies that may result in sub-optimal outcomes.

> In reality, however, the information necessary to implement efficient 'price discrimination' will often be unavailable. Importantly, imperfect price discrimination may have significant and adverse impacts on service use and thereby on efficiency.[193]

Access seekers also face significant information asymmetries.

> Negotiation between access seekers and providers can be affected by imbalances in information available to the parties. In particular, the service provider will have a greater appreciation of the cost and price structures of the services in question, their technical operation, the degree of spare capacity and the scope for capacity augmentation. Such information imbalance weakens the bargaining position of the access seeker.[194]

and

> To enable the access seeker to determine the appropriateness of the terms and conditions offered, the service provider should provide sufficient information to allow the access seeker to make a reasonable assessment of the basis on which those terms and conditions were made. This requires that such information include relevant details about the costs associated with operating the facility and providing the service.[195]

As observed by the Parer Review, access to adequate information is critical to the proper functioning of markets.

> For markets to function properly, participants need access to sufficient information. The Panel believes the provision of information to the market regarding the nature and pricing of pipeline services (similar to that required by the Gas Code) is an important mechanism to address the information asymmetry between pipeline companies and users and to enable the market to function properly.[196]

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191 Productivity Commission (2001), *Part IIIA*, p. xxi.
192 Productivity Commission (2001), *Part IIIA*, p. 38.
193 Productivity Commission (2001), *Part IIIA*, p. 47.
194 Productivity Commission (2001), *Part IIIA*, p. 205.
195 Productivity Commission (2001), *Part IIIA*, p. 211.
196 Parer Review (2002), p. 195.

The regulatory processes under the Code provide regulators and market participants with substantial quantities of information in order to facilitate market processes and negotiations. Indeed, the concept of a reference tariff provides the market with a considered view as to the appropriate level of tariffs that will balance the interests of all parties.

In the absence of regulator review of information provided by service providers, users must draw on their own resources to assess the information provided. To the extent that users are small entities with limited resources, the users may be at a significant disadvantage in the negotiation process. In addition, significant resources may be saved by providing for one significant review by a regulator, rather than individual reviews by a potentially large number of users.

While regulators may be subject to regulatory error owing to information asymmetry, users would also be subject to errors without the information provisions of the Code.

Distributional issues

The pursuit of monopoly pricing can have consequences in terms of income distribution:

> … So too will monopoly pricing of services, even if access is provided to all those seeking it. Such behaviour is also likely to affect income distribution — although whether such impacts will be material depends on the particular circumstances.[197]

The Productivity Commission has previously concluded that access regulation is not an appropriate mechanism for pursuing distributional goals.

> … In particular, given that infrastructure services such as communications, power and water are essential for basic quality of life, there are distributional consequences to be considered. However, as discussed in chapter 6, access regulation is unlikely to be an effective or appropriate instrument for targeting distributional outcomes.[198]

However, to the extent that access regulation results in distributional outcomes that are generally regarded as desirable, these benefits should be captured in the cost-benefit analysis.

Adjustment costs

After five years of application, outcomes under the Code have achieved a substantial level of stability and predictability. Most coverage issues have now been resolved (or are close to resolution) and most transmission and distribution access arrangements have been settled, with some entering their second iteration. In addition, the GasNet and MAPS access arrangements are currently being reviewed in the Tribunal which will add to the volume of jurisprudence surrounding the Code.

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[197] Productivity Commission (2001), *Part IIIA*, p. 45.
[198] Productivity Commission (2001), *Part IIIA*, p. 57.

As a consequence, investors are now experiencing a high level of comfort with the outcomes that can be expected under the Code. This comfort is illustrated in a recent report by Moody's Investors Services:

> Moody's maintains a stable outlook on regulated electricity and gas transmission and distribution (T&D) companies in Australia and New Zealand. Supportive regulatory frameworks, conservative management strategies, and stable operating and financial profiles generally ensure medium-term rating stability.[199]
>
> Tariff decisions in 2002 for Victorian gas distributors, gas and electricity transmission companies as well as South Australian electricity transmission firms demonstrate that overall regulatory philosophies are fairly stable and predictable, at least in Australia. Signs are that this will remain so over the medium term, and that the tariff resets scheduled in 2006 for Victorian and South Australian electricity distributors will reflect this situation. In fact, we anticipate regulatory stability, at least until 2010.[200]
>
> The ESC and the ACCC's decisions represent evidence – in Moody's opinion – that Australia's current regulatory framework is reasonably stable and predictable. The regulators have applied – with consistency – their methodologies and philosophies in determining lines company revenues. For these reasons, we believe that they will follow these same principles in the next tariff reset. The next significant regulatory event is the tariff reset for electricity distribution companies in Victoria for 2006-2010. Moody's does not expect the cash flows and debt coverage measures of our rated electricity distribution companies to be materially affected at that reset.
>
> Importantly, the regulators continue to apply incentive-based pricing methodologies that encourage companies to more efficiently operate their networks. At the same time, the companies are allowed to keep certain portions of their efficiency gains – the excess over the regulators' operating costs, capital expenditure and cost of funds targets.
>
> Given recent precedents and the regulators' announced intentions, Moody's does not believe that they would adopt a more aggressive stance by clawing back these excesses in the medium term. Australian T&D companies will continue to enjoy stable and predictable regulatory regimes, supporting their cash flows and credit profiles until the end of the next reset – that is – by 2010.[201]

Should the Productivity Commission consider recommending adjustments to the current regime, it would be appropriate to consider the level of implementation or adjustment costs that might be encountered in moving to the new regime. This was a factor in the Part IIIA Review:

> While the Commission sees an in principle case for focussing more explicitly on monopoly power and efficiency issues, it has doubts whether, at this juncture, the benefits of introducing new and untested declaration criteria would be large enough to exceed the accompanying implementation and adjustment costs. Indeed, settling the interpretation of a completely new declaration package could take several years.[202]

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199 Moody's Investors Service (2003), *Australian/NZ Regulated Distribution and Transmission 2003 Outlook: Stable, but event risk to drive some credit profiles*, July 2003, p. 1.

200 Moody's (2003), p. 1.

201 Moody's (2003), p. 3.

202 Productivity Commission (2001), *Part IIIA*, p. 190.

Costs of regulatory compliance

To date there has been limited research on the costs of regulatory compliance with the Code. For example, in respect of the costs incurred by government the Productivity Commission stated in its Part IIIA review that:

> The Commission did not attempt to estimate the costs incurred by the Commonwealth Government in relation to Part IIIA, or by the States and Territories in administering their various industry access regimes. However, in an aggregate sense, these costs are unlikely to be all that large:[203]

However, when the costs of compliance with the current regime are considered as part of a cost-benefit analysis, it is critical that the net costs of compliance are estimated and that only costs directly attributable to the current regime are included. Such an estimate can be made by applying a with and without test. As noted by the Productivity Commission, not all compliance costs currently encountered are unique to the current regime.

> However, not all of the compliance costs referred to above can be attributed to access regulation. In an unregulated environment, commercial negotiations on access matters would not be costless. Also, the protracted nature of decision making to date is partly because access regulation in Australia is still very much in the development phase. As more decisions are made and precedents established, the general timeliness of decision making may well improve.[204]

On the government side, it is likely that significant compliance costs would continue to be encountered if the current regime were replaced with an alternative. In addition to the adjustment and implementation costs that would arise in setting up the new regime, government resources would continue to be required to administer and enforce the new regime. Government resources will continue to be required in developing energy policy no matter what type of regime is in place. Arguably, the current regime is less resource intensive for governments than the previous regime where State governments were heavily involved in developing, operating and regulating pipeline systems.

On the industry side, it is first necessary to isolate the costs that are solely attributable to the current regime. Regulated businesses and users engage in a range of activities such as lobbying governments, submissions to reviews and industry association activities that should be excluded from any estimate of compliance costs. In addition, in the absence of the current regime, industry would continue to encounter many of the costs currently incurred and may well encounter additional costs. For example, the costs incurred in developing a base set of terms and conditions with the regulator might be replaced with the costs of negotiating multiple access agreements with prospective users.

When the potential costs of multiple access agreements are considered, it may well be the case that compliance costs in the current regime are less than the costs of a regime that does not entail a benchmark terms of access.

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[203] Productivity Commission (2001), *Part IIIA*, p. 60.
[204] Productivity Commission (2001), *Part IIIA*, p. 63.

Further, a new set of adjustment and implementation costs would be encountered should a new regime be applied.

6.2 Conclusion on cost and benefits

Owing to the non-exhaustive nature of the analysis set out above it is not possible to draw a firm conclusion on the net benefits of the current regime. However, there is clear evidence to suggest that the current regime is delivering significant net benefits to the industry and the economy. Further, there are indications that these benefits could be exceeding the nets costs of the regime by a significant margin.

These views are supported by a significant reduction in access prices, suggestions of past denial of access, a high level of investment in the industry, emerging upstream and downstream competition, increased consumption of gas and limited net compliance costs.

Chapter 7 Governance

7.1 Hilmer Report

In August 1993, the Independent Committee of Inquiry into National Competition Policy released its final report, the Hilmer Report. The report marked a milestone in the microeconomic reform of the Australian economy and laid the foundation for extending the scope of the TPA,[205] introducing Part IIIA (Access to services),[206] establishing the ACCC and the National Competition Council.[207] In considering the operation of national competition policy, the Hilmer Report gave consideration to the appropriate governance arrangements for the administration of the national access regime and the TPA. The Hilmer Report endorsed the use of a generalist economy wide regulator:

> In particular, the Committee considers that there are sufficient common features between access issues in key network industries to administer them through a common body. As well as the administrative savings involved, there are undoubted advantages in ensuring regulators take an economy-wide perspective and have sufficient distance from particular industries to form objective views on often difficult issues.[208]

In 1995, the *Competition Policy Reform Act* amended the TPA establishing the ACCC as a generalist economy wide agency with regulatory and competition law enforcement responsibilities.

The ACCC as a generalist regulator

The ACCC has responsibility for regulating a wide-range of industry sectors, such as the gas[209] and electricity markets,[210] airports,[211] rail,[212] telecommunications[213] and postal services.[214] In conjunction with these responsibilities the ACCC has also administered the TPA assessing matters relevant to the energy sector in relation to matters such as mergers and authorisations.

The ACCC's generalist role ensures that it undertakes a wide range of activities in the energy industry. In addition to approving access arrangements, the ACCC assesses authorisations in the upstream gas industry and those for the independent system operator, the Victorian Energy Networks Corporation, of the GasNet System in Victoria.

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205 National Competition Policy (1993), *Report by the Independent Committee of Inquiry*, Ch. 5.
206 National Competition Policy (1993), *Report by the Independent Committee of Inquiry*, Ch. 11.
207 National Competition Policy (1993), *Report by the Independent Committee of Inquiry*, Ch. 14.
208 National Competition Policy (1993), *Report by the Independent Committee of Inquiry*, p. 327.
209 *Natural Gas Pipelines Access Agreement* (1997) and Part II of the TPA.
210 National Electricity Code and the National Electricity Market Access Code lodged under Part IIIA and Part VII of the TPA, also Part II of the TPA.
211 *Airports Act 1996* (Cth), *Prices Surveillance Act 1983* (Cth) and Part II of the TPA.
212 Part II and Part IIIA of the TPA.
213 Part II and Part XIB and Part XIC of the TPA, in addition to the *Telecommunications Act 1997* (Cth) and related legislation.
214 *Australia Post Corporation Act 1989* (Cth) and Part II of the TPA.

Under the current regulatory framework, regulators often work together on specific issues and co-operate more formally through the Utility Regulators' Forum and the ACCC's Energy Committee. The Regulators' Forum comprises economic regulators from the Commonwealth and each of the States and Territories.[215] The twelve regulators cover the energy, transport, and water sectors. The regulators meet quarterly to inform one another about their activities and to discuss issues of common interest such as pricing principles.

The Energy Committee, which is part of the ACCC, comprises representatives from the ACCC and State energy regulators acting in their capacity as ex-officio members of the Commission. It reviews electricity and gas regulatory matters before the ACCC. The Regulators' Forum and the Energy Committee represent co-operative arrangements that help to achieve regulatory consistency and there has been progress towards regulators adopting common approaches and working more closely together.

7.2 Parer Review

In its final report, the Parer Review proposed changes to the institutional governance arrangements that apply to the energy sector. These reforms were intended to overcome a number of deficiencies identified in the current governance arrangements for the energy sector. The Parer Report was of the view that its reform proposal would bring with it, amongst other things:

- An independent regulator that is accountable to all jurisdictions, not simply the Commonwealth;
- A drastic reduction in the number of regulators with which energy businesses have to do business;
- A greater regulatory consistency to assist in the development of national energy markets; and
- More streamlined code change processes.[216]

The Review proposed the creation of a National Energy Regulator (NER) to encompass the energy specific roles of the ACCC, all the State and Territory regulatory bodies, and some of the roles of National Electricity Code Administrator (NECA). The proposed regulator would be an energy sector only regulator.

In relation to the gas industry, it was proposed that a Gas Advisory and Code Change Committee be established, supplanting the National Gas Pipelines Advisory Committee and the Gas Policy Forum.[217] Its key role will be to propose and analyse changes to the Code proposed by market participants.[218] It would also provide briefing to the Ministerial Council of Energy (MCE) on gas policy matters as needed.[219]

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[215] Regulators Forum participants: Australian Competition and Consumer Commission, Independent Pricing and Regulatory Tribunal (NSW), the Essential Services Commission (Victoria), the Queensland Competition Authority, Office for the Gas Access Regulator (WA), Office of Water Regulation (WA), the South Australian Independent Pricing and Access Regulator, the South Australian Independent Industry Regulator, the Government Prices Oversight Commission (Tasmania), Office of the Tasmanian Energy Regulator, the Independent Competition and Regulatory Commission (ACT) and the Utilities Commission (Northern Territory).

[216] Parer Review (2002), p. 84.

[217] Parer Review (2002), Recommendation 2.8.

[218] Parer Review (2002), Recommendation 2.8(a).

[219] Parer Review (2002), Recommendation 2.8(b).

The Review recommended a common Ministerial approach on all electricity and gas issues within Australia. It proposed that the MCE subsume the role of the National Electricity Market (NEM) Ministers Forum to allow for a more national, gas and electricity, perspective.[220] Once implemented the MCE will have a key role in agreeing on the laws that will govern the energy sector across Australia. The MCE will also appoint the NER Commissioners and members of the Gas Advisory and Code Change Committee.[221]

The Parer Review noted several concerns regarding inappropriate incentive structures in existing regulatory governance frameworks, specifically:

> Many submissions referred to the conflict of interest that can exist when government bodies determine the rules and administer regulations affecting markets in which their own businesses operate. The risk of in appropriate control being exercised by governments is magnified when they own a high proportion of both generators and retailers operating within a particular regional market, as is the present case in jurisdictions other than Victoria and South Australia.
>
> Structures that create potential conflicts of interest can lead to inappropriate influence. Whether or not this actually occurring, it is an unhealthy arrangement and deters investment.
>
> Ultimately the Panel's concerns centre on the problems that are caused for the development of energy markets when perceptions of a possible conflict of interest appear to be widely held.[222]

Concerns about the outcomes that might arise because of the incentives brought about by government ownership of public utilities, along with regulatory and other governmental responsibilities have appeared since the Parer final report. Specifically there is concern that State and Territory governments might become reliant upon extracting higher than necessary dividend payments from their state-owned utilities to ensure a positive fiscal position.

The Network Economics Consulting Group[223] notes that the payment of special dividends by utilities is acceptable where there is no profitable investment opportunity for surplus cash. However, a problem can arise when taking such dividends becomes an entrenched practice which might cause cash-flow problems even for firms with a strong balance sheet if such payments occur for a sustained period. The eventual outcomes could be a diminished capacity for state-owned utilities to maintain investment in their infrastructure. It is therefore important to provide the right framework for regulatory governance to avoid the perceptions referred to by Parer.

7.3 Industry Minister's views

The Minister for Industry, Tourism and Resources put forward further options for reforming the energy market in November 2002, prior to the release of the Final Parer Report.[224] Amongst the elements of the proposed reform program was Minister

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220 Parer Review (2002), Recommendation 2.12 and 2.13.

221 Parer Review (2002), Recommendation 2.2 and 2.9.

222 Parer Review (2002), pp. 78 – 79.

223 Australian Financial Review (Hepworth, Aanbel and Drummond, Mark) (8 Aug. 2003), *Are the States bleeding their energy utilities dry?*, p. 72.

224 Minister for Industry, Tourism and Resources (2002), Media Release (25 November): *Bringing Australia's energy market out of the dark*, Attachment http:///www.minister.industry.gov.au.

Macfarlane's option for the creation of a new institutional governance structure for the energy industry.

The Macfarlane Model proposes that the MCE takes sole responsibility for the Australian energy market by subsuming the NEM Ministers' forum. The MCE would assume responsibility for the overall policy and strategic objectives of the energy market.

In terms of industry regulation, an Australian Energy Commission would be created to act as a single national energy regulator. In addition, an Australian Energy Market Management Company would be established to operate as service provider and system operator for gas and electricity markets nationwide. The Minister also proposed the establishment of the Australian National Energy Corporation to undertake development activities in the national market.

7.4 Ministerial Council on Energy

The MCE is responsible for leading and coordinating the development of energy policy in Australia. It includes representatives from Commonwealth, state and territory governments. At the June 2003 meeting, the MCE agreed that it would report to CoAG that further reform would be undertaken to strengthen the quality, timeliness and national character of governance of energy markets. In addition more work would be needed to streamline and improve economic regulation across energy markets. As a first step, Ministers agreed to the governance model outlined below, subject to consideration by each jurisdiction, to progress at subsequent MCE meetings.

The proposed governance model includes, establishing the Australian Energy Regulator (AER), to regulate electricity and gas transmission networks. The AER, would be governed by Commissioners, one of whom would be from the ACCC, with the remaining Commissioners appointed by the NEM Ministers forum or its successor organisation.[225] Furthermore, cooperative arrangements between the ACCC and the AER would be worked out officer level.[226] The NEM Ministers forum would be replaced by the MCE.[227]

The proposed model envisages the development of a national regulatory framework for distribution and retailing to commence in 2004.[228] A separate rule making body, the Australian Energy Market Commission, reporting to the NEM forum or its successor, would be established.

7.5 Other reviews

The Productivity Commission has undertaken several reviews concerning industry sectors that operate with access regimes, these include the telecommunications and airports industries. In addition the Productivity Commission has also reviewed the operation of Part IIIA of the TPA.

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[225] Ministerial Council on Energy (June 2003), *Communique*: Attachment, 2.A, 2.B.
[226] Ministerial Council on Energy (June 2003), *Communique*: Attachment, 2C.
[227] Ministerial Council on Energy (June 2003), *Communique*: Attachment, 6.
[228] Ministerial Council on Energy (June 2003), *Communique*: Attachment, 9.

In its report on the telecommunications sector released in September 2001, the Productivity Commission recommended that the ACCC continue in its role as the relevant regulator maintaining current arrangements.

> The choice between specific versus generic regulator should take account of any transaction costs with creating the new body. Shifting to a new entity would involve some, but not appreciable, transitional costs. The TPA would require amendment, while a new entity would require a careful description of its functions, well specified governance arrangements and substantial expert staffing – probably from the ACCC.
>
> Without a compelling argument for a shift to a telecommunications-specific regulator, this suggests that the status quo be preserved.[229]

In response to the Productivity Commission telecommunications report, the Commonwealth Government agreed with the recommendation for the ACCC to continue as the regulator, noting that:

> There is little evidence that supports one form of regulation over another, however, generic regulators are able to bring advantages such as lower fixed costs, the capacity to deal with converging sectors, while being free from having a vested interest in industry specific regulation.[230]

The Productivity Commission inquiry report, released on 23 January 2003, into airport regulation did not specifically address the issues of regulatory governance as part of that review. The final report did, however, recommend that price monitoring occur of major airports occur from 1 July 2002 for a period of five years, with the authority to do so contained in legislation administered by the ACCC. This approach was endorsed in the Commonwealth's final response, issued in May 2002, to the Productivity Commission report. The ACCC is currently undertaking its price monitoring role.

Similarly, the Productivity Commission's review of Part IIIA of the TPA did not specifically consider the issue of administration on that part of the Act, and therefore left the current arrangements with the ACCC as the multi-sector regulator in place. The Commonwealth's interim response, released in September 2002, to the Productivity Commission's final report did not signal the federal government's intention to change the current administration of Part IIIA of the TPA.

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229 Productivity Commission (2001), *Telecommunications*, pp. 307 – 308.

230 Commonwealth Government (2000, Aug.), *Government response to the Productivity Commission Report on the review of the telecommunications competition regulation*, Government response to Recommendation 10.2.

Chapter 8 Areas for improvement

In considering the operation of the Code, the ACCC believes that there are some areas for further improvement in order to better meet the objectives of the Code. These are: the access arrangement approval process; switching services; the treatment of expansions of pipeline capacity for covered pipelines; section 41 notices; fixed principles and the competitive tendering provisions of the Code.

8.1 Access Arrangement approval process

There is a long and involved process set out in Section 2 of the Code that regulators must follow when considering whether to approve a proposed access arrangement. Below is a brief summary of the key steps.

- Lodgement of the proposed access arrangement and access arrangement information (AAI) by the service provider.
- The Code requires the ACCC to then inform each person it knows that has an interest in the matter and to publish an ad in a national newspaper describing the pipeline to which the access arrangement applies and seeking submissions by a particular date (which must be at least 28 days after the publication of the notice).
- The ACCC typically also prepares and publishes an Issues Paper inviting public comment on the access arrangement. Submissions from interested parties facilitate the ACCC's assessment of the proposed AA and its preparation of a Draft Decision.
- Consideration by the ACCC whether the AAI meets the requirements of ss.2.6 and 2.7, namely that it contains sufficient information to enable users and prospective users to understand the derivation of the elements in the proposed access arrangement and to form an opinion as to its compliance with the Code. If it does not, the ACCC must require the service provider to make the appropriate changes to its AAI within a reasonable period.
- Release of the Draft Decision for public comment and further request for submissions (must be at least 14 days after release of the Draft Decision – but typically is at least 28 days).
- The ACCC considers submissions in response to the Draft Decision.
- The ACCC releases a Final Decision.
- If a complying access arrangement is submitted, the ACCC issues a second final decision, known as a Final Approval and the access arrangement becomes effective.
- If a complying access arrangement is not submitted, the ACCC must draft and approve its own access arrangement.
- If the ACCC drafts and approves its own access arrangement, the decision may be reviewed by the Australian Competition Tribunal.

Section 2.21 of the Code requires regulators to complete this access arrangement approval process within six months of receiving a proposed access arrangement – although the Code provides for regulators to extend this time period in increments of no more than two months at a time so long as they publish a public notice to that effect in a national newspaper.

For a number of reasons, this six month timeframe has proved extremely difficult for regulators to achieve. There was a large group of initial access arrangements to be

approved in the first few years of the Code's operation, which have required some time to work through. The approval process requires a significant amount of public consultation on the various proposals and decisions. In practice, the approval process has been more iterative than envisaged, with additional consultation required each time service providers amend their proposal.

It is important that future access arrangement approvals be made in a more timely manner. The ACCC believes this is achievable with some changes to the current approval process. Given the imminent completion of the first round of access arrangements, this is a good time to make some procedural changes.

The ACCC's experience has been that service providers often submit a number of proposed amendments to access arrangements during the approval process. This has had the effect of significantly delaying the process. Removal of the second final decision would place greater importance on the Draft Decision and significantly reduce the level of iteration in the process.

The ACCC believes that additional restrictions on the ability of service providers and regulators to make new amendments late in the process will also significantly reduce the approval process timeframes.

While some flexibility with respect to amendments to a proposed access arrangement prior to the Draft Decision is desirable, this practice can cause significant and unnecessary delay after the Draft Decision. The ACCC believes that to make it possible for the six month approval timeframe envisaged in the Code to be achievable, a change is required to limit proposed revisions to an access arrangement by service providers to within 28 days of the Draft Decision. This will enable the regulator to proceed to a Final Decision in a timely manner.

Some additional restrictions on the degree of discretion the regulator has when making its Final Decision are also required. These proposed changes would modify the approvals process as follows:

- Lodgement of the proposed access arrangement and access arrangement information (AAI) by the service provider.
- Public consultation on proposal.
- Consideration by the regulator of the AAI.
- Release of the Draft Decision.
- Service provider has 28 days to provide a revised access arrangement. Any further amendments to the access arrangement are heavily restricted.
- Public consultation on Draft Decision and any response by service provider.
- Service provider provided right of response to any issues raised in consultation.
- The regulator releases its Final Decision.
- Right of appeal under administrative law only.

Opportunities to amend a proposed access arrangement

There is nothing in section 2 of the Code that appears to prevent a service provider from submitting amendments to a proposed access arrangement on an on-going basis. There have been cases where service providers have submitted several rounds of

amendments to the first access arrangement originally submitted for approval. While some flexibility is required, it is important to recognise that each time a service provider amends its proposed access arrangement, the relevant regulator is required to ensure that all interested persons are treated fairly. In many cases this requires a further round of consultation. This can make the timely consideration of a proposed access arrangement impossible.

The ACCC believes that a degree of flexibility is required prior to the relevant regulator's Draft Decision. For example, where initial consultation reveals an obvious problem with the proposed access arrangement, it may be preferable to amend the proposed access arrangement at that stage. Accordingly, the ACCC does not propose any specific prohibition on a service provider's ability to amend its proposed access arrangement prior to the Draft Decision. However, the ACCC does believe that, where such an amendment is submitted, it must have the ability to 'stop the clock' while it undertakes any further consultation that is necessitated by the amendment.

However, once the relevant regulator has published its Draft Decision, the opportunities to submit amendments to the proposed access arrangement need to be curtailed. At this stage of the process the proposed access arrangement has been through a thorough consultation process and the relevant regulator has published its proposed decision. While it is essential that the service provider has an opportunity to submit revisions in response to the Draft Decision, it should not be able to continue to do so as the relevant regulator moves towards its Final Decision. Further amendments to the proposed access arrangement will require additional consultation and, possibly, the publication of additional preliminary views by the relevant regulator. This has the potential to substantially delay the finalisation of the assessment process and can make it impossible for the relevant regulator to meet the deadline contained in the legislation.

To deal with this issue, the ACCC proposes that the service provider be given a single, clear opportunity to submit amendments in response to the Draft Decision. Once this is done, the relevant regulator can then undertake a further round of consultation with interested persons seeking comments on both the Draft Decision and any proposed amendments by the service provider in response.

It should also be emphasised that a service provider can, if it wishes, simply make a submission responding to a Draft Decision rather than propose amendments. For example, the service provider might simply wish to argue that an amendment specified in the Draft Decision should not be required. In this case, the service provider would have no need to submit an amended access arrangement. It need only argue that the relevant regulator withdraw an amendment which it had required in the Draft Decision.

The scope of amendments to a proposed access arrangement

There is also a need to review and clarify the scope of the amendments that can be submitted by a service provider in response to a Draft Decision. There have been cases where, following a Draft Decision, a service provider has submitted what is, in substance, a new access arrangement. This might require the ACCC to re-start its analysis and assessment process. It also raises issues of procedural fairness (for example, what further consultation is required? Is a further Draft Decision required?).

Section 2, as it currently stands, does appear to attempt to limit the scope of the amendments that can be considered by the relevant regulator to amendments that:

- incorporate, or substantially incorporate, the amendments required by the relevant regulator; or
- otherwise address the matters identified by the relevant regulator as the reason for requiring the amendments (see, for example, s 2.15A and 2.19).

The ACCC supports this limitation on amendments to a proposed access arrangement and believes that this needs to be confirmed in section 2 of the Code. However, in addition, the ACCC believes that amendments to a proposed access arrangement should also be permitted where they are a direct and necessary consequence of an amendment that is required by the relevant regulator in the Draft Decision or an amendment proposed by the service provider in response to a Draft Decision. For example, if the relevant regulator requires an amendment that has a consequential impact on another part of the access arrangement, the service provider should be able to propose such an amendment. Alternatively, the relevant regulator should be able to require such an amendment in its Final Decision. The ACCC believes that this would provide an appropriate balance between the need for flexibility following its Draft Decision and the need to ensure that the relevant regulator can move to a Final Decision in a timely manner.

Final Approval

The further Final Decision (or "Final Approval") required by s 2.19 and s 2.20 (or s 2.41 and s 2.42) is, in the ACCC's opinion, an unnecessary step in the assessment process. It is relatively rare that a decision making process requires the regulator to, in effect, make two draft decisions. This extra step in the process tends to lessen the importance of the first Draft Decision, since the service provider has not one but two further opportunities to address the regulator. The Final Approval causes several months of delay, while adding relatively little to the quality of the decision making process. The ACCC submits that the Final Approval could be removed, and that the relevant regulator's consideration of the proposed access arrangement should end with the Final Decision.

Final Decision

There is also a need to review the degree of discretion permitted to the relevant regulator when making its Final Decision. For example, if the relevant regulator has specified certain amendments in the Draft Decision, but accepted the rest of the proposed access arrangement, should the relevant regulator be able to make additional amendments in the Final Decision to parts of the access arrangement that had previously been approved (assuming they are not consequential amendments)? If the relevant regulator has specified an amendment in the Draft Decision, can the relevant regulator instead require a different amendment to address the relevant issue? Can the relevant regulator simply withdraw the amendment on the basis that it is satisfied that it is no longer required?

Assuming that the Final Decision is the final step in the relevant regulator's assessment of a proposed access arrangement, the ACCC submits that the Code could provide the following degree of discretion to the relevant regulator in relation to the Final Decision.

Where the service provider does not submit amendments to its proposed access arrangement in response to a Draft Decision

The relevant regulator must either:

(a) accept the access arrangement originally proposed by the service provider (so, for example, the relevant regulator simply accepts the original access arrangement or, if it required amendments in the Draft Decision, it can accept that they are no longer required); or

(b) reject the proposed access arrangement and draft an amended access arrangement. The amendments would be limited to:
   (i) the amendments initially required in the Draft Decision;
   (ii) amendments that otherwise address the matters identified in the Draft Decision as being the reasons for requiring the amendments (so, for example, if the Draft Decision specified an amendment to the access arrangement, and the relevant regulator had been persuaded that there was a better way to address the relevant issue, the relevant regulator could adopt that alternative. In such a case, the general principles of administrative law would usually require the relevant regulator to consult with affected persons as required); or
   (iii) amendments that are a direct and necessary consequence of (i) and (ii).

For the avoidance of doubt, the Code should provide that the relevant regulator can withdraw an amendment that it had specified in its Draft Decision (that is, where the service provider had not proposed amendments in response to the Draft Decision, but had convinced the relevant regulator that an amendment should no longer be required).

Where the service provider does submit an amended access arrangement in response to the Draft Decision

The relevant regulator must either:

(a) approve the amended access arrangement proposed by the service provider; or

(b) reject the proposed access arrangement and publish an amended access arrangement.

The relevant regulator would only be able to accept the amended access arrangement where the amendments:

(a) incorporate or substantially incorporate the amendments specified in the Draft Decision;

(b) otherwise address the matters identified in the Draft Decision as being the reasons for requiring the amendments; or

(c) are a direct and necessary consequence of amendments referred to in (a) or (b).

Similarly, where the relevant regulator publishes its own access arrangement, the amendments would be limited to these same matters.

Again, for the avoidance of doubt, the relevant regulator would also be able to approve an amended access arrangement where it was satisfied that an amendment specified in the Draft Decision was no longer required.

Proposed changes to the access arrangement approval process

Revisions prior to the Draft Decision

1. A service provider can submit amendments to its proposed access arrangement prior to the Draft Decision. However, for the purposes of any statutory deadline that applies to the relevant regulator's decision, time would not run while the relevant regulator was undertaking any further consultation necessitated by the amendments.

Revisions following the Draft Decision

1. The service provider may, within 28 days of the Draft Decision, re-submit the access arrangement with amendments that:
   (a) incorporate or substantially incorporate the amendments specified by the relevant regulator in the Draft Decision;
   (b) otherwise address the matters the relevant regulator identified in its Draft Decision as being the reasons for requiring the amendments; or
   (c) are a direct and necessary consequence of amendments referred to in (a) or (b);

   together with any submission in support of the amended access arrangement.

2. The relevant regulator would not be required to consider any amendments not accompanied by an AAI that complies with s 2.9.

3. Alternatively, the service provider can make a submission responding to the Draft Decision without proposing amendments to the access arrangement.

Consultation on the Draft Decision and amended access arrangement

1. Following the receipt of any amended access arrangement and/or submission from the service provider, the relevant regulator would invite submissions on the Draft Decision and any proposed amendments from interested persons. The ACCC also envisages that the relevant regulator would give the service provider a right of reply, addressing matters raised by interested persons.

Final Decision

1. If no amendments to the proposed access arrangement are received in response to the Draft Decision, the relevant regulator must either:
   (a) approve the access arrangement originally proposed; or
   (b) publish its own access arrangement, containing amendments that:
      (i) incorporate or substantially incorporate the amendments specified in the Draft Decision;
      (ii) otherwise address the matters identified in the Draft Decision as being the reasons for requiring the amendments; or
      (iii) are a direct and necessary consequence of amendments referred to in (i) or (ii).

   For the avoidance of doubt, the relevant regulator can publish an access arrangement that does not contain an amendment specified in the Draft Decision where the relevant regulator is satisfied that the amendment is no longer required.

2. If amendments are proposed by the service provider in response to the Draft Decision, the relevant regulator must, subject to paragraph 3 below, either:
   (a) approve the amended access arrangement proposed by the service provider; or
   (b) not approve the amended access arrangement and publish its own access arrangement that contains the amendments that would be necessary for it to have been approved.

3. The relevant regulator would be able to approve an amended access arrangement or publish its own amended access arrangement only if it is satisfied that the amendments:

   (a) incorporate or substantially incorporate the amendments specified in the Draft Decision;
   (b) otherwise address the matters identified in the Draft Decision as being the reasons for requiring the amendments; or
   (c) are a direct and necessary consequence of amendments referred to in (a) or (b).

   For the avoidance of doubt, the relevant regulator can approve and amended access arrangement or publish an access arrangement that does not contain an amendment specified in the Draft Decision where the relevant regulator is satisfied that the amendment is no longer required.

Merits review of decisions relating to access arrangements

Part 6 of the Gas Pipelines Access Law ("GPAL")[231] provides for administrative appeals against certain decisions of the relevant regulator.

Section 39 establishes a right of appeal to the relevant appeal body against a decision of the relevant regulator:

- to draft and approve an access arrangement (s 2.20) or revisions to an access arrangement (s 2.42) in place of an access arrangement or revisions proposed by a service provider;
- to draft and approve an access arrangement where the service provider fails to submit an access arrangement as required by the Code (s 2.23) or to draft and approve revisions where the service provider fails to submit revisions as required by the access arrangement (s 2.45); and
- to disallow and substitute a variation to a reference tariff under s 8.3E of the Code.

In effect, s 39 of the Law provides for a 'limited merits review' of these types of decisions. The limitations upon this type of review are as follows:

- the grounds upon which an application for review may be made are limited to:
  (a) an error in the relevant regulator's findings of facts;
  (b) that the exercise of the relevant regulator's discretion was incorrect or unreasonable having regard to all the circumstances; and
  (c) that the occasion for exercising the discretion did not arise;

[231] Schedule 1 to the *Gas Pipelines Access (South Australia) Act 1997.*

- the applicant may not raise any matter that was not raised in submissions to the relevant regulator before the decision was made;[232] and
- the appeal body must not consider any matter other than:
  a) the application for review and submissions in support of it (provided that, in the case of a review of a decision under s 2.20 or 2.42, no new matter is raised);
  b) the relevant access arrangement or proposed access arrangement and the related access arrangement information or, in the case of a review of a decision under s 8.3E, any notice of the proposed variation to the reference tariff;
  c) any written submission made to the relevant regulator before the decision was made;
  d) any reports relied on by the relevant regulator before the decision was made;
  e) any draft decision and any submissions to the relevant regulator on the draft decision;
  f) the relevant regulator's decision and its reasons; and
  g) the transcript of any hearing conducted by the relevant regulator.

The ACCC has been party to three appeals to the Australian Competition Tribunal under s 39 of the GPAL. These are:

- DEI Queensland Pipeline Pty Ltd v ACCC [2002] ACompT 2[233] (review of the ACCC's Final Approval under s 2.20 with respect to the Wallumbilla to Rockhampton pipeline (also known as the Queensland Gas Pipeline) ("the QGP appeal"));
- *Application by GasNet Australia (Operations) Pty Ltd*; heard 13-21 August 2003, decision reserved (review of the ACCC's Final Approval under s 2.42 with respect to the GasNet Transmission System) ("the GasNet appeal"); and
- *Application by Epic Energy South Australia Pty Ltd*; heard 1-2 September 2003, decision reserved (review of the ACCC's Final Approval under s 2.20 with respect to the Moomba to Adelaide Pipeline System) ("the MAPS appeal").

The time required for the conduct of these appeals and the nature of the issues considered call into question whether an avenue for merits review of decisions of the relevant regulator in relation to access arrangements should be retained in the GPAL.

The Administrative Review Council (ARC) has published a guideline entitled "*What Decisions should be subject to Merit Review?*" Paragraph 2.1 of this guideline states:

> As a matter of principle, the Council believes that an administrative decision that will, or is likely to, affect the interests of a person should be subject to merits review. That view is limited only by the small category of decisions that are, by their nature, unsuitable for merits review, and by particular factors that may justify excluding the merits review of a decision that otherwise meets the Council's test.

The ARC goes on to identify a range of factors that may justify excluding merits review. Broadly speaking, these are grouped into:

- factors lying in the nature of the decision;

[232] This limitation does not apply with respect to a decision under s 8.3E of the Code.
[233] (2002) ATPR 41-876.

- factors lying in the effect of the decision; and
- factors lying in the costs of the review of the decision.

The factors described in the third group are:

Decisions involving extensive inquiry processes

4.53. This exception covers decisions that are the product of processes that would be time-consuming and costly to repeat on review.

4.54. Such processes include public inquiries and consultations that require the participation of many people. If review of the subsequent decisions was undertaken, the nature of the review process would be changed from the normal adjudicative decision-making process (of, say, the AAT), to a greatly expanded and time-consuming one.

4.55. For example, the Council has advised that decisions made under the *Australian Heritage Commission Act 1975* to enter, or not to enter, a place on the Register of the National Estate would be inappropriate for external merits review, if the Act was amended to provide for those decisions to be made by a process involving public hearings.

Decisions which have such limited impact that the costs of review cannot be justified

4.56. Merits review costs money. Given that the Government must allocate resources in an effective way, it would obviously be inappropriate to provide a system of merits review where the cost of that system would be vastly disproportionate to the significance of the decision under review.

4.57. For example, merits review of a decision not to waive a filing fee of, say, $150 may be difficult to justify on an economic basis. That said, the cost of review must be accounted for not only by comparison with the extent of the interests of any individual that may be affected, but also by comparison with the broader and beneficial effects that merits review is intended to have on the overall quality of government decision-making.

The ACCC believes that the first of these factors justifies the exclusion of merits review in relation to the relevant regulator's consideration of an access arrangement or revisions to an access arrangement. Deciding whether to accept an access arrangement requires the ACCC to investigate and consult widely with the parties who may be affected by the decision. The relevant regulator's decision has the potential to impact on a large number of people (for example producers, users and potential users). This process of consultation is interactive, in that it often involves the on-going exchange of information and views with affected persons over the course of the decision making process. A full merits review of such a decision (involving a re-determination of the relevant regulator's decision) would require a similar investigative process, rather than the adjudicative process typically used by a body such as the Australian Competition Tribunal. The cost and time involved in such a process would far exceed that usually involved in the conduct of a typical merits review.

In relation to the second of the points extracted above, the ACCC does not submit that a decision in relation to an access arrangement can be characterised as insignificant. However, the ACCC does question whether the benefits associated with merits review in this case outweigh the costs.

The merits review process adds significant delay to the finalisation of an access arrangement. The QGP appeal (which was confined to a single question of law) took

approximately 6 months. The GasNet appeal (which covers a wider range of issues) took approximately 7 months to get to the hearing stage. The MAPS appeal took over a year to get to the hearing stage. When added to the time taken for the original decision, this additional delay has the potential to create significant uncertainty about the basis for the future regulation of a gas pipeline.

This uncertainty can affect investment decisions not only by pipeline operators but by potential users. For example, a potential user who may wish to seek access to a gas pipeline may be unable or unwilling to seek to negotiate access until the terms and conditions that will be applicable under the access arrangement are finalised.

The ACCC's experience is that affected parties are more likely to take issue with a determination of the relevant regulator on a discreet issue (or series of issues) rather than the overall approach of the relevant regulator or the full range of findings that are involved in assessing a proposed access arrangement. To expose the entire determination to re-determination in order to provide an avenue for review of the specific issues of concern has the potential to cause a degree of delay and uncertainty that is not justified by the benefits that are achieved by having this avenue for review. This is especially the case where the regulator's determination on a particular issue can, in most cases, be reviewed by a court under an application for judicial review.[234]

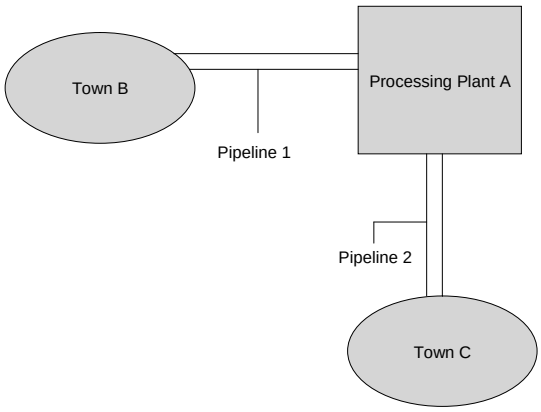
The current provisions in s 39 of the GPAL for limited merits review do not satisfactorily address the issues identified above. Even this limited process causes substantial delays. The time frames referred to above in relation to the QGP, GasNet and MAPS appeals all relate to the limited merits review process (a full merits review process for these matters would be expected to take even longer). Given the limitations on a review under s 39, and the delay that is still associated with this type of review, the ACCC submits that the costs of this process (in terms of delay and uncertainty) outweigh its benefits.

8.2 Switching services through processing facilities

The ACCC has received complaints from a number of gas industry participants suggesting that owners of gas processing facilities have refused to supply switching services. A number of Australia's gas processing facilities have more than one pipeline taking gas from them. This creates the possibility of the processing facility providing basic 'hub' services – effectively switching gas from one pipeline to the other.

With reference to the diagram below, the following scenario seeks to demonstrate the issue of concern. A company in Town B at the end of Pipeline 1 has 5TJ/day of excess contracted gas which it advertises for sale. A company in Town C agrees on a price to buy that gas. It then negotiates with Pipeline Company 1 to 'backhaul' that gas from Town B up to the head of the pipeline. It also comes to an arrangement with Pipeline Company 2 to transport the 5TJ/day down to Town C.

[234] For example, see *Re Michael; Ex Parte Epic Energy (WA) Nominees Pty Ltd* [2002] WASCA 231; (2002) ATPR 41-886 (judicial review by the WA Court of Appeal of OFFGAR's draft decision in relation to the access arrangement for the Dampier to Bunbury Pipeline).



Physically, the 5TJ/day of gas cannot flow back up Pipeline 1 from Town B to Processing Plant A, since the pipeline flows in the opposite direction. What can happen, however, is the operator of Processing Plant A simply withholds 5TJ/day that it would otherwise have pumped into Pipeline 1 and increases the flow into Pipeline 2 by 5TJ/day. Clearly this requires that sufficient capacity is available on Pipeline 2, and there may be some physical restrictions to overcome due to the configuration of the processing facility and the location of the respective pipeline's offtake points within the facility. Typically, while some minor expenditure may be required, such a transaction should be relatively simple and if the customer is willing to pay a reasonable fee for the transaction, the facility operator should be willing to provide what is essentially a transportation or 'switching' service.

Complaints have arisen, however, because the owners of some processing facilities are also gas suppliers. This creates an incentive for them not to provide the switching service, to restrict the entry of a potential competitor into a market they already supply.

Using the above example to illustrate this point, assume Gas Producer 1 constructed Processing Plant A to enable it to process its gas produced from the surrounding region and then supply gas to customers in Towns B and C through Pipelines 1 and 2. As in the previous example, imagine a company with gas being supplied to it at Town B wishes to resell 5TJ/day of that gas to a user in Town C.[235]

To effect this transaction, it negotiates with the owners of Pipelines 1 and 2 with respect to transportation. There is, however, no way for the two pipeline companies to effectively 'move' the 5TJ/day from one pipeline to the other without the assistance of the operator of Gas Processing Plant A, since it is only through this facility that they are connected.

Gas Producer 1 operates the processing plant and has little incentive to enable the switch, since without the switch, the only alternative supplier for that gas demand in Town C is itself. It is clearly in the commercial interests of Gas Producer 1 to frustrate the ability of the parties concerned to give effect to their desired transaction. This

[235] It is not critical to this example whether the customer at Town B is purchasing the gas it wishes to resell from Gas Producer 1 or from a different supplier.

incentive is strengthened if, as is commonly the case, the gas sales contract is on a take or pay basis – requiring the customer in Town B to pay for the gas even if it can't use it.

The only legal recourse against such behaviour at present is through section 46 of the Trade Practices Act (misuse of market power). However, section 46 has proven to be extremely difficult to prosecute generally and is not regarded as an effective remedy for this situation. As an alternative, a physical bypass might be constructed, that is, a new pipeline that connects the two pre-existing pipelines outside of the processing plant.

Physical bypass can be costly, depending on the size and length of the line needed, and would, in most cases, be unnecessary were it not for the vertical linkages between ownership of gas processing facilities and gas suppliers. Nevertheless, the ACCC understands that at least three bypass pipelines have been built. One connecting the Moomba to Sydney and Moomba to Adelaide pipelines just outside the Moomba gas processing centre. Another connecting the Ballera to Wallumbilla pipeline to the Ballera to Mt Isa pipeline just outside the Ballera gas processing centre. A third has been built for similar reasons connecting the Wallumbilla to Gladstone pipeline with the Ballera to Wallumbilla pipeline.

The ACCC believes that the construction of bypass pipelines in these instances is a signal of market failure. It shows that the entry of potential competitive gas suppliers to existing markets has been restricted, in direct contrast to the objectives of gas reform. The ACCC has had reports of gas sales unable to proceed because the cost of bypass was too high given the value of the desired transaction.

There is no ability for gas industry participants to seek assistance via the existing Code or national access regime, since gas processing facilities are explicitly exempt from both. The 'service' sought here, however, is not a gas processing service, and is more akin to a transportation service.

The ACCC believes that access seekers should be entitled to negotiate access to this 'transportation service' through a gas processing facility with some recourse to regulation in much the same way that they can seek access to pipelines.

It is important to distinguish this issue from the more commonly discussed issue of whether third party access to upstream gas processing facilities should be provided. Third party access to gas processing facilities typically refers to the ability for other gas producers to be able to negotiate to have their gas processed at an existing facility and if that negotiation broke down, to have recourse to some form of regulation.

Third party access to gas processing facilities has been proposed a number of times as a possible measure to encourage entry of new players into the upstream gas sector with the hope of new discoveries being made in existing basins resulting in greater supply competition. Indeed the recent Ministerial Council on Energy Communiqué, dated 1 August 2003, supports a review of third party access to upstream facilities as a potential means of increasing the penetration of natural gas, lowering energy costs and improving energy services.

The issue being raised here, however, is not about access to the service of processing gas – it is really one of transportation or switching processed gas between various pipelines that emanate from the processing facility.

8.3 Expansions of pipeline capacity

The capacity of a gas pipeline, the quantity of gas that can be transported through it in a given time period, is not fixed. It is primarily a function of a pipeline's diameter and the pressure of the gas. Gas pipeline operators use compressors to raise the pressure of gas within a pipeline and hence increase the deliverable flow, or capacity. Different types of pipe have different maximum safe operating pressure ratings, to ensure that the gas pressure is not so high as to rupture the pipe wall. This means that compressors need to be spread out over the length of a pipeline to maximise their ability to increase capacity.

Pipeline operators typically construct new pipelines with a compressor at the head of the pipeline (although sometimes gas flowing out from a processing plant is of sufficient pressure not to require this) such that the capacity of the pipeline is roughly able to meet the initial demand. This means that if demand grows over time, additional compressors can be added to the pipeline to increase the capacity. Compression typically provides a lower per unit cost of capacity than the original per unit cost of laying the pipeline, although there are diminishing returns from compression. The ACCC understands that once a typical gas pipeline has 7 compressor stations spread along its route, the returns from additional compression are unlikely to outweigh the costs.

At this point, should further capacity be demanded, a pipeline operator will start 'looping' its pipeline. This is effectively laying additional pipe alongside the original pipeline and interconnecting them so gas flows through them simultaneously and pressure is equalised across both. The physics of gas flows means that by looping just one section of a pipeline, the capacity of the entire pipeline can be increased.

Typically looping is significantly more expensive per unit of capacity than compression, but still significantly more economical than the construction of a brand new pipeline by another party. This is because the pipeliner looping its pipe has significant common costs in operation and can also save on construction – given it has access to the current easement and much of the necessary construction infrastructure in place. Looping also provides an ability for a pipeline company to incrementally increase capacity as demand grows, rather than having to invest in a whole new pipeline in one lump sum.

All of this supports the conclusion that natural gas pipelines tend to have natural monopoly characteristics – and not just for the initial capacity/demand that they are constructed to meet. Indeed, as the quantity of demand for gas transportation services approaches the capacity of a pipeline, pipeline owners have an additional opportunity to exert market power over access seekers, even if the pipeline is a covered pipeline under the Code.

Expansions create opportunities to exercise market power

As a pipeline approaches full capacity, further demand prompts consideration of an expansion of capacity. In these circumstances, pipeline companies can take advantage of the competitive tension between existing users and prospective users to increase the price of access in negotiations.

An existing customer has a strong incentive to agree to the terms offered by the service provider at the expiry of its contract, because if it does not agree then the capacity might be allocated to a new user. While the pipeline can always be expanded if there is sufficient additional demand, there is uncertainty about the regulatory treatment of expansions and this creates an incentive for prospective users to pay the price being asked. Potentially, the service provider can raise its prices up to the cost of the next best alternative.

In these circumstances regulatory intervention is required to provide users with confidence that expansions will be priced on a fair and reasonable basis in order to remove the incentive to pay the service provider's potentially excessive asking price.

Pipeline extensions do not give rise to similar concerns. When an extension to a pipeline is proposed, there is potential for an alternative entity to construct the extension to the new customer and then interconnect with the existing pipeline. This should sufficiently constrain the existing pipeline's ability to increase prices for access to the extension.

The Code's approach to expansions

The Code recognises that one of the necessary elements for an effective access arrangement for a natural gas pipeline is a policy setting out how any capacity from an expansion is to be treated – in terms of access prices and terms and conditions.

Section 3.16 of the Code 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.[236] 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 need for a presumption of coverage

A common approach by service providers to extension/expansion policies as part of proposed access arrangements has been that the service provider will nominate at the time of an extension/expansion whether or not it become part of the covered pipeline. Service providers have argued that should access seekers believe an extension/expansion should form part of the covered pipeline, then they can always apply to have it covered.

[236] For example, reference tariffs may remain unchanged, but a surcharge may be levied on incremental users.

The problem with this approach is that the threat of coverage is in itself insufficient to deter service providers from seeking to impose unreasonable terms on a prospective user of expanded capacity. At the time of the negotiation, users have no recourse to dispute resolution mechanisms under the Code, nor to arbitration, until such time as the expansion is covered. Users cannot apply to have the expansion covered until it is under construction.[237]

For these reasons, when considering an access arrangement for pipelines where there is a very real prospect of an expansion being required within the access arrangement period, the ACCC has required service providers to amend the extensions/expansions policy. This issue is addressed by having an extensions/expansions policy that specifies that all expansions will be treated as part of the covered pipeline unless the service provider nominates that they not be and the regulator agrees.

This presumption of coverage enables a prospective user to lodge an access dispute if it is unsatisfied with the outcomes of commercial negotiations over access to expansion capacity.

The ACCC required the Australian Pipeline Trust to amend its expansions policy to this effect for the Wallumbilla to Brisbane pipeline, which it did. The ACCC also required Epic to amend its expansions policy for the Moomba to Adelaide Pipeline System access arrangement. Epic appealed against this element of the ACCC's Final Approval decision (amongst other elements). Immediately prior to the hearing, however, Epic indicated that it did not intend to pursue its application for review of this particular element of the Final Decision.

The ACCC believes it has the legal power to require such an amendment under the Code. However, there is still some uncertainty on this issue. For example, Offgar took a different view in respect of the DBNGP. As a result, an amendment is necessary to clarify the Code's ability to address the pricing of capacity expansions for covered pipelines.

It is worth noting that this is not just a theoretical issue. Arguably an example of such an attempt to exercise market power has arisen in the context of the Dampier to Bunbury Pipeline in Western Australia. Epic Energy has been reported to be seeking higher prices from its customers in order to guarantee supplies of gas given the pipeline's capacity is becoming constrained and an expansion is required. In the West Australian it was reported that:

> EPIC Energy, owner of the Dampier-to-Bunbury gas pipeline, is in advanced negotiations with WA's biggest gas users over a radical plan aimed at circumventing the controversial price ruling last month by the regulator.
>
> Epic said yesterday the deal would give it the financial return it needed from the pipeline to justify investing in a $300 million expansion, ensuring that key users would have access to additional gas supplies.

[237] This is because the relevant definition of a pipeline under the Code does not in this instance include a prospective pipeline.

> Under Epic's proposal, gas users such as Alinta, Western Power and a string of manufacturers would agree to pay Epic more - probably up to 10 per cent - to transport their gas than the regulator's decision requires them to pay …
>
> The pipeline is now operating at maximum capacity and Epic, which paid $2.4 billion for it in 1997, is refusing to expand the line unless it is allowed to raise transport prices.[238]

Pricing of capacity from expansions

A related issue is how capacity arising from an expansion to a pipeline should be priced. Clause 3.16(b) of the Code requires that an access arrangement specify how any covered extension or expansion would affect the reference tariff. The two alternatives are a rolled-in tariff or an incremental cost approach.

Under an incremental cost approach, prospective users would pay a tariff that reflected the cost of incremental capacity. For example, one method is for the incremental user to pay the reference tariff plus a surcharge for the costs of the expansion which are not met by the addition to the service provider's revenue.

An incremental cost approach raises potential concerns:

- There is likely to be multiple tariffs for the same service and a level playing field would not exist in down stream markets. If prospective entrants into either gas retail or electricity generation markets had to pay significantly higher tariffs for gas transportation, this might affect their ability to compete in those markets and therefore the likelihood and effectiveness of their entry. This could result in either new entry being limited, or that such entry is unable to act as a competitive constraint on incumbents.
- However, market participants have submitted that multiple tariffs are not uncommon and are not necessarily inappropriate. Irrespective of whether future expansions are rolled-in, different tariffs can be paid for expansions that were contracted in recent years. Further, it is possible that users and the service provider will negotiate tariffs commercially rather than adopt the reference tariff so it is possible that multiple tariffs will exist even if the costs of expansions are rolled-into the capital base.

Nevertheless, the ACCC does not consider that multiple tariffs for the same service is an optimal outcome.

- If an incremental cost approach to expansions is adopted, existing capacity can be cheaper than developable capacity and there is likely to be excess demand for existing capacity as it becomes available. Some form of mechanism to allocate this capacity is then required. In the absence of a roll-in at some point, the difficulty in allocating the capacity will remain and reoccur each time contracts expire.
- The incremental costs of expansion are not constant. For example, the next few stages of expansion on the Moomba to Adelaide Pipeline System are relatively expensive and would produce relatively little additional capacity. Therefore, prospective users may be reluctant to finance an expansion of the pipeline.

On the other hand, rolling-in the costs of expansions is also problematic. For example:

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238 The West Australian, *Epic plots new gas deal*, 25 June 2003, p. 53.

- A rolled-in tariff may deter investment in an alternative pipeline. Under a roll-in, the cost of expansion is averaged over all users. Therefore prospective users would not pay the marginal cost of incremental expansion but the average cost of all capacity. As a result, expansion of an existing pipeline is likely to be preferable on the basis of cost than the development of a new pipeline for prospective users. This disincentive for a new pipeline to be constructed can prevent the entry of a competitor.
- A rolled-in tariff, particularly one which estimates tariffs depending on the amount of expansion which takes place, results in a degree of uncertainty for users.

Clearly there are advantages and disadvantages of both pricing approaches. Determining which approach is preferable involves assessing the balance of these advantages and disadvantages given the circumstances of a particular pipeline.

Incremental pricing may be more appropriate for one pipeline, while rolled-in pricing is more appropriate for another. It may even be the case that the most appropriate pricing approach for expansions on a particular pipeline will change over time.

For these reasons, it is important that regulators continue to have sufficient flexibility under the Code to exercise appropriate discretion when considering expansion policies as part of the approval process for access arrangements.

8.4 Competitive tenders under the Code

Obtaining reference tariffs by way of the competitive tendering provisions outlined in sections 3.21 to 3.36 of the Code can be an attractive alternative to proceeding via section 8 of the Code. This is especially the case where governments may wish to facilitate the development of a new pipeline. The competitive tendering provisions are based on sound theory. However, not all tender processes conducted under the Code have led to optimal results. This is because of two main reasons. First, some tenders have been used in situations where a pipeline would face marginal or negative returns. Second, in other cases restrictive conditions have been imposed on potential bidders. In addition, some of the competitive tendering provisions of the Code may require further consideration and benefit from possible adjustment.

Running a competitive tender may compare well, in terms of cost and time, with determining reference tariffs in accordance with the principles in section 8 of the Code. However, small communities wishing to attract a supply of natural gas should consider all regulatory options, both under the Code and also under Part IIIA of the *Trade Practices Act 1974* (the Act).

The competitive tendering process

The Code provides that reference tariffs may be set by a competitive tendering process, as an alternative to setting reference tariffs in accordance with the principles outlined in section 8. The theory behind this is that competition for the market, via the tender process, will be an appropriate proxy for competition in the market.

Before carrying out the tender, the person wishing to conduct the tender must submit a Tender Approval Request (TAR) to the regulator for approval. Section 3.28 of the Code

provides that the regulator must approve the request if all criteria outlined in this section are met, and must not approve the request if any of the criteria is not satisfied. These criteria include s 3.28 (f)(i) – that the successful tenderer will be selected principally on the basis that the tender will deliver the lowest sustainable tariffs to users generally over the economic life of the proposed Pipeline.

Once the TAR has been approved, the tender may be conducted. The person or organisation conducting the tender may then apply to the regulator for final approval of the reference tariffs. If the regulator grants final approval, the pipeline then becomes a covered pipeline, and the tariff determined by the tender process becomes the reference tariff.

The ACCC considers that the competitive tendering provisions are sound in theory. The proposition that competition for the market can substitute for competition in the market appears to be correct, provided the tender process is genuinely competitive. However, many of the tenders conducted to date have experienced practical difficulties. These are described below.

The Loddon Murray Tender

On 30 August 2001, the Loddon Murray Gas Supply Group (LMGSG) submitted a TAR for the supply of natural gas to the Loddon Murray region to the ACCC and the Victorian Office of the Regulator - General (ORG). The application was made under section 3.21 of the Code.

The Loddon Murray region is in northern Victoria. The tender process was conducted for the Rural City of Swan Hill and the municipalities of Loddon and Gannawarra. The project was estimated to be worth $50m and, if successful, would potentially supply 15,000 gas consumers in the region.[239]

The TAR received approval from the ACCC on 1 November 2001, and from the ORG on 30 October 2001.

Having obtained regulatory approval, the LMGSG proceeded with the tender process. No conforming bids were received. However, four parties indicated a keen interest in providing natural gas to the region. The ACCC was later advised that the LMGSG would be continuing negotiations with these parties outside of the competitive tender process.

The Yarra Ranges Tender

The ORG received a TAR from the Yarra Ranges Shire Council to conduct a competitive tender to supply natural gas to the region, in early 1999.

The population of the region is estimated at 14,000.[240] The AGA estimates the value of the project at $16m.[241]

[239] AGA Response to Energy Market Review Draft Report, p. 25.
[240] AGA Response to Energy Market Review Draft Report, p. 25.
[241] AGA Response to Energy Market Review Draft Report, p. 25.

The Office approved the TAR and the Shire of Yarra Ranges tendered for the supply of gas. The Shire advised that no conforming bids were received.

The East Gippsland Tender

In 1997 the East Gippsland Shire Council carried out a tender to determine the preferred gas supplier and retailer to the region of East Gippsland including the urban centres of Bairnsdale, Lakes Entrance, Paynesville and Orbost. The tender covered the provision of distribution and retail services. EastCoast Gas (a joint venture between Eastern Energy, the Victorian electricity distribution and retail company, and Westcoast Energy Australia, a subsidiary of a major North American gas company) was selected by the Council as preferred tenderer in October 1997.

In June 1998 EastCoast Gas submitted to the Office of the Regulator General (now the Essential Services ACCC) an access arrangement in respect of the proposed gas distribution system for approval under the *Victorian Third Party Access Code for Natural Gas Pipeline Systems* (the Victorian Code).

In May 1999 the ORG issued a Final Decision approving the tender outcome.

One interesting point to note in relation to this tender is that EastCoast Gas, in its access arrangement information submitted to the ORG on 26 June 1998, estimated demand for this pipeline as 600,000 GJ per year within 10 years, rising to nearly 800,000 GJ per year within 20 years.[242] The project was valued at $14m.[243]

This pipeline has not yet been built. However, as the project has received full regulatory approval from the ORG, this cannot be attributed to any shortcoming on the part of the regulatory regime.

The Central Ranges Tender

On 3 January 2003 the Central Ranges Natural Gas and Telecommunications Association Incorporated (CRNG&TAI) submitted a tender approval request (TAR) to the ACCC and to the Independent Pricing and Regulatory Tribunal (IPART) to conduct a competitive tender under the Code.

The proposed tender is for the construction of a transmission pipeline and distribution network to supply natural gas to the Central Ranges region of New South Wales. The proposal does not require specific towns to be supplied, however, the CRNG&TAI expects that the successful tenderer would service at a minimum Mudgee, Tamworth and Gunnedah.

On 12 March 2003 the ACCC released its Decision approving the TAR. IPART approved the TAR on the same date.

The tender for this pipeline is currently being conducted.

[242] Access Arrangement Information submitted by EastCoast Gas 26 June 1998, p. 7.
[243] AGA Response to Energy Market Review Draft Report p. 25.

The Tasmanian Tender

Following commencement of Duke Energy's Tasmanian Natural Gas Pipeline, the State of Tasmania sought to run a competitive tender process, consistent with the Code, to distribute and retail natural gas in Tasmania. To this end, a TAR was submitted to the Office of the Tasmanian Energy Regulator on 7 September 2001. The TAR was approved in November 2001.

The Tasmanian tender was run in 2002. The tender process was terminated by the State, as no tenders satisfactory to the State had been received. Since then, a tender process has been run outside the requirements of the Code, and a successful tenderer has been selected.

It has been suggested that the tender run under the auspices of the Code failed to produce an acceptable outcome due to the onerous nature of requirements imposed by the Code. For example, Mr Paul Lennon MHA, Tasmanian Deputy Premier and Minister for Economic Development, Energy and Resources, stated in his second reading speech for the *Gas Infrastructure (Miscellaneous Amendments) Bill 2003* (No. 39):

> As the Tasmanian experience has shown, the tender process specified in the Code is heavily regulated, slow, inflexible, complex, resource intensive and costly for both a Government to administer and proponents to participate in.[244]

However, the ACCC believes this view should be appraised in the light of several comments made by Aurora and Agility in relation to the tender process. Aurora and Agility expressed dissatisfaction with some of the requirements imposed by the tender process.

1. The Gas Pricing Order

One of the regulatory instruments to which successful tenders would have been subject was the Gas Pricing Order (GPO). Aurora and Agility expressed some concerns in relation to this instrument. For example, Aurora and Agility considered that the CPI-X escalation regime imposed by the GPO placed unnecessary restrictions on tariffs. Aurora and Agility considered that this requirement might prevent bidders from offering the lowest possible cost to consumers.[245]

2. Purchase of the Launceston distribution system

A mandatory requirement of the tender process was that as part of its submission, a bidder was required to make an irrevocable offer to enter into an agreement to purchase the Launceston town gas distribution system 'at a fair and reasonable price determined by an independent valuer'.

At the time of the tender, Origin Energy owned the Launceston distribution system, and this requirement was intended to put Origin on an equal footing with other bidders.[246]

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[244] Mr Paul Lennon MHA, second reading speech for introduction of Gas Infrastructure (Miscellaneous Amendments) Bill 2003 (No. 39), Thursday 29 May 2003, p. 32.

[245] Aurora and Agility submission p. 22.

[246] Tasmanian Gas Tender – Tender Approval Request Decision and Statement of Reasons (TAR Decision), p. 51.

Aurora and AGL commented on this requirement:

> Origin is likely to seek to maximise the sale price (with cost impacts for other bidders) while knowing the true nature of the operational status of the Launceston network.
>
> The Consortium is of the view that the Launceston network has very little, if any, value given the non-operational status of this network…Further, the potential exists for transferred unquantifiable and significant liabilities (e.g. environmental, explosions, public liability) to impact adversely on the financeability of any bid that is required to include the LNSA.[247]

3. Uniform Retail Tariffs

The Office of the Tasmanian Energy Regulator's Tender Approval Request Decision (TAR Decision) noted:

> It is a mandatory requirement that there be uniform retail tariffs across the bidder's proposed service area for customers that have the same demand and load characteristics and consume less that 30 TJ per annum.[248]

Aurora and Agility commented on this requirement:

> The Consortium has a number of concerns regarding the mandatory requirement for uniform retail tariffs as currently proposed by the State.
>
> Prospective commercial and industrial users of natural gas will have varying changeover costs depending on their current energy sources and requirements. Prudent discounting may be required to encourage some customers to change over to natural gas. This will enable higher gas volumes to be achieved with consequently lower reference tariffs for all customers.[249]

4. Other mandatory requirements

In their submission, Aurora and Agility also argued that other mandatory requirements imposed by the tender process were too restrictive.[250] Aurora and Agility also commented in relation to the requirements for conforming bids:

> It is also the view of the consortium that the requirements for Conforming Bids are too restrictive. These restrictive requirements, coupled with the fact that Non-Conforming Bids may be rejected at the State's discretion means that a proposal which delivers the lowest sustainable cost to consumers through the most efficient tariff regime may not necessarily be considered for evaluation by the State.[251]

5. Other issues arising from the Tasmanian tender

In addition to the issues mentioned by Aurora and Agility, the ACCC notes several aspects of the Tasmanian tender, such as:

- the minimum pipeline route stipulated by the tender documents, which included Hobart, Launceston, Burnie, Devonport and Ulverstone;
- the requirement for distribution and retail bids to be stapled; and

247 Aurora and Agility submission, p. 15.
248 TAR Decision p. 51.
249 Aurora and Agility submission p. 25.
250 Aurora and Agility submission p. 20.
251 Aurora and Agility submission p. 20.

- the requirement that bidders enter a connection agreement with Duke prior to submitting their bid.

These conditions should also be considered in evaluating the outcomes of the Tasmanian tender.

Are the competitive tendering provisions leading to unsatisfactory outcomes?

As described above, some tenders run under the auspices of the Code have led to unsatisfactory outcomes. However, it appears that the principal problem in several of these tenders was a lack of commercial viability of the underlying project. This may have been due to the marginal nature of some of these proposals. When running a competitive tender process, there is a need for sufficient demand to attract pipeline service providers as is the case with any infrastructure project requiring significant investment. Preferably this should include significant foundation contracts to underpin the high fixed costs of constructing a pipeline.

Without sufficient demand, whilst the organisation running the tender process may receive regulatory approval, the project may still not attract suitable bidders. The competitive tender process cannot compensate for insufficient levels of demand for natural gas to provide a return on the cost of the necessary pipeline investment.

From the tender processes detailed above, there appear to be no issues of timeliness in relation to obtaining regulatory approval. In all cases, the relevant regulator has approved the tender approval request in a timely manner – generally several months. This approval has occurred without the imposition of onerous terms on the tender process.

Areas for improvement in competitive tendering

Notwithstanding the comments above, there appear to be some aspects of the competitive tendering provisions that could be improved.

First, there is currently no scope for a person who has submitted a TAR to make minor changes to the TAR prior to its approval by the regulator. If the person wishes to make changes to the TAR, technically they must issue a new TAR.
Furthermore, the regulator cannot require changes to the TAR as part of its approval process. Having sought public consultation on the TAR, the regulator can either approve or not approve the TAR. Should significant issues arise during public consultation, or should the regulator consider that changes are warranted, there is no scope to amend the TAR.

Second, the Code does not specifically provide guidance on how a conditional bid should be treated within the selection process of a tender. For example what weighting should a low bid which is conditional on project finance approval be given when also considering a high bid which has project finance approved? This given that the successful tender should be selected principally on the basis of the delivery the lowest sustainable tariffs. Under the competitive tendering provisions, a bid is either conforming or non-conforming.

There may be scope to amend the tendering provisions to explicitly allow conditional bids to be submitted and for a ranking of suitable bids, rather than just the selection of a single 'winning' bid. For instance, bids might be submitted on condition that essential elements such as finance, finality of costs, other government approvals and foundation contracts come to fruition. Furthermore, if these conditions were not fulfilled, there should be scope for award of the tender to pass to the next most suitable bidder. This would provide more flexibility in the tendering process, and might encourage more conforming bids for tenders where immediate pipeline returns are uncertain.

Third, several tenders to date have been for combined distribution and transmission pipelines. To achieve this, the person submitting the TAR must submit it to both the ACCC (for the transmission pipeline) and the relevant State authority (for the distribution pipeline). This involves a significant degree of duplication. There is scope to streamline this process to make it simpler for a person to tender for both a transmission and distribution system simultaneously and to have the process considered by a single regulator.

Conclusions on competitive tendering

Some competitive tenders conducted under the Code have led to unsatisfactory outcomes. This appears to have resulted from several sources, principally a lack of commercial viability of proposals, as well as conditions placed on bidders by the governments or councils running the process. Nevertheless, improvements to the competitive tendering provisions might be achieved through minor changes.

Furthermore, in circumstances where there is not strong interest from prospective pipeline developers, regional councils should consider whether it is necessary to obtain gas supplies through the regulatory channels provided by the Code. The pipeline, when constructed, might be unlikely to attract regulation. Pipeline proponents should discuss this matter with the NCC, and should also take cognizance of recent NCC revocation and coverage decisions.

8.5 Section 41 notices

Section 41 of the Gas Pipelines Access (South Australia) Act 1997 provides a power to regulators to obtain information and documents to assist it in the performance of its duties under the Code.

Currently, failure to comply with any requirement made under section 41 carries a maximum penalty of $10 000 or imprisonment for 12 months. This exposure to criminal sanctions is perceived to be heavy handed.

Section 41 notices are typically used in a regulatory context rather than an enforcement context – that is seeking further information to enable the ACCC to properly consider an aspect of a proposed access arrangement. The additional significance of having criminal liability rather than just a civil sanction can make section 41 notices less likely to be used.

The record keeping rules in the telecommunications regulatory regime under Part XIB of the Trade Practices Act 1974 provide an example of a regulatory information provision requirement that has civil sanctions rather than criminal.

The ACCC believes that a civil penalty is a sufficient measure in these circumstances and would enable regulators to better use this information gathering tool.

8.6 Fixed principles

Section 8.47 of the Code enables a service provider to propose that certain principles within its access arrangement be fixed for a specified period of time. This means that they would not be subject to review and possible change at formal access arrangement reviews within that specified time period.

Given most access arrangement periods run for 5 years, fixed principles are designed to provide greater regulatory certainty to service providers for longer term aspects of their regulatory approach – such as depreciation schedules or revenue sharing mechanisms.

The current wording of section 8.47 is that fixed principles, once agreed, may not be changed within the specified period without the agreement of the service provider. It does not explicitly state that the agreement of the regulator is also required.

This means that the regulator is bound by the fixed principle but the service provider may not be. This could lead to undesirable outcomes, such as where the fixed principle is the introduction of a benefit sharing mechanism that carries benefits or losses into the subsequent access arrangement period. If the service provider does not like the outcome in the subsequent period (for example a negative carryover eventuates) then it may not be bound to comply with the mechanism.

This asymmetry can be addressed by amending section 8.47 such that fixed principles may not be changed within the specified period without the agreement of both the service provider and the regulator.

Attachment 1 On workable competition

On "workable competition", "Replicating the Outcomes of Competitive Markets" and The Implications of the Epic Decision

Darryl Biggar

26 August 2003

1. Many regulatory regimes specify that the one of the objectives of regulation should be to replicate those outcomes which would arise under a competitive market. But competitive markets come in many shapes and sizes, and evolve over time. What sorts of markets are to be emulated and which outcomes are to be replicated?

2. This was one of the issues facing the West Australia Supreme Court in the Epic Decision.[252] The Australian Code specifies that the regulator is, amongst other things, to "replicate the outcomes of a competitive market". In that decision, the Court interpreted the phrase "competitive market" to refer to a "workably competitive market". What did the Court intend by the term "workable competition" and, more importantly, precisely what outcomes did the Court seek to promote through this decision?

3. The key points of this note are the following:

- The notion that regulatory decision-makers should seek to regulate in such a way as to replicate the outcomes of a competitive market is widespread but of limited practical usefulness. There are a wide range of competitive markets with different outcomes. Policy-makers must select which outcomes of which competitive markets they will seek to replicate. More fundamental welfare notions, such as economic efficiency, can provide a guide as to which outcomes should be selected.

- The concept of "workable competition" was developed in an attempt to delineate those markets in which competition yielded broadly acceptable outcomes. Therefore the notion that regulatory decision-makers should regulate in such a way as to replicate the outcomes of a "workably competitive" market is equivalent to saying that regulatory policy-makers should pursue broadly acceptable outcomes. I conclude that the Court's interpretation of "competitive market" as "a workably competitive market" does not, in itself, provided significant guidance to regulators.

- The Court, in the Epic decision, does go on to articulate particular properties that it would like to see pursued by regulators, including incentives for efficiency and reward for taking risk. This can be interpreted as saying that, within the range of competitive markets which regulators might emulate, the Court prefers those in

[252] Re Dr Ken Michael AM; Ex Parte Epic Energy (WA) Nominees Pty Ltd. & Anor [2002] WASCA 231.

which adjustment to equilibrium is not too rapid and in which sunk costs are important. This aspect of the Court's decision does provide useful, if limited, guidance for regulators.

- The Court does not, in my view, argue against the use of economic efficiency as a broad guide for policy-makers. Neither does the Court argue that regulatory outcomes should involve persistent monopoly rents.

The Use of the "Competitive Market Principle" in Regulating Non-Competitive Markets

4. As already noted, it is widely accepted that regulators, in seeking to regulate the prices of natural monopolies, should seek to replicate the outcomes of competitive markets. For example, in a classic text by Alfred Kahn:

> … the single most widely accepted rule for the governance of the regulated industries is regulate them in such as way as to produce the same results as would be produced by effective competition, if it were feasible.[253]

5. This view has, in many cases, been explicitly codified into the rules governing regulatory regimes. For example, section 8.1 of the Code states that "A reference tariff and reference tariff policy should be designed with a view to achieving the following objectives: … (b) replicating the outcome of a competitive market". Section 6.1.1(b) of the National Electricity Code states that the key principles governing transmission pricing are intended to "regulate the market for network services in a way which seeks the same outcomes as those achieved in competitive markets".

6. Let's refer to this principle – that regulators should seek to mimic the outcomes that arise under competitive markets – as the "competitive markets principle" or ("CMP").

7. For clarity, it is important to be clear exactly what the CMP is saying. The CMP applies to the regulation of markets which cannot sustain competition (most usually due to the presence of a natural monopoly). The CMP *does not* say that natural monopoly markets should be regulated in the same way as competitive markets. That would be nonsensical – not least because competitive markets require virtually no price regulation at all. Nor does it say that natural monopoly markets should be regulated so as to achieve competition as would occur in competitive markets (if they were feasible). Rather, the CMP says that natural monopoly markets should be regulated so as to achieve *the same outcomes* as is normally expected to arise under effective competition. In other words, the CMP is not a statement about how regulation should be carried out, but merely about what end-points that regulation is to achieve.

[253] Kahn, Alfred E (1988), The Economics of Regulation, Principles and Institutions Volume I, MIT, p. 17.

Key Problems With The "Competitive Market Principle"

8. The CMP is a useful shorthand way of summarising the sorts of outcomes that policy-makers would like to see pursued under regulation, but does it have much practical usefulness as a guide to regulatory decision-making?

9. Competitive markets come in many different forms, with varying properties (markets in taxi services are different from markets in computer software, which are, in turn, different to markets in used cars and to markets in pharmaceuticals). The features or outcomes of these markets can be quite different from each other. Which markets should the regulator seek to emulate and which outcomes should the regulator select? What should the regulator do if some of these outcomes turn out to be in conflict in the context of regulation of natural monopoly? Or, if a completely different outcome would improve overall welfare?

10. For example, it is well known that a key property of competitive markets is that each firm chooses to produce a quantity at which the marginal cost of that firm is equal to the market price. Does this imply that the regulator should set the regulated price of a natural monopoly equal to its marginal cost? In the case of a natural monopoly (unlike a competitive market) this will guarantee (by definition) that the regulated firm will not be able to recover its total costs. Another property of competition between roughly identical firms is that entry drives prices down to the point where each firm is producing at the minimum of its average cost curve. Should this outcome be replicated in a natural monopoly market?

11. In fact, as is clear, although both average-cost pricing and marginal-cost pricing are simultaneously possible in competitive markets, they are mutually incompatible in natural monopoly markets.[254] Which of these two outcomes should the regulator choose to replicate? The CMP provides no guidance.

12. Another property of competitive markets is that the revenue from any service or any group of services cannot be above the stand-alone cost for the provision of that service or services (such prices would be undercut by a new entrant). Similarly, the revenue from any service or any group of services cannot be below the incremental cost for a service. Nevertheless, it is possible to construct examples which show that welfare could be improved if prices were above the stand-alone cost for one or more services. While this is not possible in competitive markets, it might be possible in a natural monopoly market. Should welfare be compromised simply to follow the CMP? Again, the CMP alone provides no guidance.

13. But the problems do not stop here. In a competitive market equilibrium where all firms have access to the same inputs, all firms must produce using the most efficient technology and processes. On the surface, this would seem to imply that the regulator in a natural monopoly market should simply set the regulated revenues equal to the level of efficient costs. But this may not be feasible. In the presence of information asymmetry, the regulator will not know what is the efficient level of costs. A natural monopoly market unlike a competitive market does not yield that information. Replicating this outcome of a competitive market is, therefore, simply infeasible.

[254] At least with simple linear prices.

14. It is known, of course, that the regulator can induce the firm to enhance its efficiency by breaking the link between the regulated firm's revenue and its costs. By adjusting the firm's revenue only slowly to changes in its costs the regulator restores some incentives for efficiency. This could be described as mimicking a competitive market – but in this case a competitive market with a relatively slow adjustment to a new equilibrium (if the adjustment of revenue to costs was too rapid the regulated firm would have little incentive to enhance efficiency). But, again, the CMP itself gives no guidance that the regulator should emulate a market with slow adjustment to equilibrium rather than rapid adjustment.

15. Finally, in a competitive market in which sunk costs are minimal, all firms could be expected to make "normal" returns. There could still be innovation and change in this industry, however, the innovation (by assumption) would not require sunk investment and so would not need to be rewarded with excess returns to cover the risk of failure. In contrast, in other competitive markets, sunk costs can be substantial. In these markets, innovative or entrepreneurial activity (such as introducing new products to new markets) is risky and must be compensated through above-normal returns in certain states of the world to offset the risk of below-normal returns in other states of the world.

16. Both markets with and without sunk costs can be competitive. Should the regulator allow above-normal returns as a reward for risk-taking? Which sort of competitive markets should regulators seek to replicate? Again, the CMP provides no guidance.

17. In practice, of course, economists do not use the CMP alone in making recommendations as to regulatory policy interventions. In fact, policy interventions are almost always measured against a more fundamental standard – which is usually the maximisation of total welfare or (equivalently) the maximisation of economic efficiency. A regulatory policy intervention is justified if it maximises total welfare or (equivalently) total economic efficiency. As is well known, this concept of efficiency is not simply a static concept but takes into account dynamic effects over time.

18. Given the ambiguity in the CMP it is not surprising that both the Code and the Electricity Code go to some lengths to set out other principles which the regulator is required to follow. For example the Electricity Code specifies that the regulator is to ensure "a commercial revenue stream to TNSPs" (ruling out marginal cost pricing in favour of average cost pricing); is to foster "efficient operating and maintenance practices" (which, amongst other things, encourages a slow adjustment of revenues to costs); is to foster "an efficient level of investment" (which, amongst other things, encourages the regulator to consider explicit rewards for risk-taking); and so on.

The competitive market principle in the Epic decision

19. Given the ambiguity in the CMP it is also not surprising that the Court in the Epic decision was called upon to interpret the clause in the Code which states that regulation should "replicate the outcome of a competitive market". As we have seen, the key question to be answered is: what are the outcomes of a competitive market which are to be emulated?

20. The Court did not directly answer this question. Instead, it sought to answer the question: what sort of competition is intended by the phrase "competitive market"? The Court briefly considered the concept of perfect competition but dismissed it as a theoretical concept:

> In the particular context of the promotion of a competitive market for natural gas it would be surprising if what was contemplated was a theoretical concept of perfect competition, as the subject matter involves very real-life commercial situations.[255]

21. Instead, the Court turned to the concept of "workable competition". As explained in the Appendix, this concept has no precise definition or boundaries. The term was coined by J M Clark in 1940. Economists had long recognised that many markets which did not meet the theoretical ideal of perfect competition nevertheless yielded outcomes which were broadly acceptable from a public policy perspective. What was needed then, was a term to describe the level of competition in such markets, which was broader than the concept of perfect competition, but not so broad as to include markets with substantial imperfections.

22. The Court held that the concept of "competitive market" which was intended in the Code was not a narrow concept (such as perfect competition) but a broad concept of a market in which competition yielded acceptable outcomes. The Court notes:

> While the concept of a competitive market is one well known in the relevant field of economics, the basic concept, in the economic sense of a workably competitive market … is one in substantial harmony with what would be understood as a matter of ordinary language by combination of the words 'competitive' and 'market'.[256]

23. There have been many attempts to list or summarise the key structure or conduct features of a market with workable competition (one such list is set out in the Appendix).[257] The Court clearly has in mind one key property of a market with workable competition – that it is a market in which "no firm has a substantial degree of market power".[258]

24. As noted in the Appendix, it is possible to derive a more fundamental definition of workable competition. Given that the notion of workable competition was intended to define the competition which occurs in markets with broadly acceptable outcomes, we may define "workable competition" as follows: a market is "workably competitive" if the outcomes of competition in that market are broadly acceptable at a public policy level.

25. Of course, in our context, this "high level" definition leads to a certain circularity. The regulator which is supposed to replicate the outcomes in a competitive market would, by this definition, be required to replicate the outcomes in markets with

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255 Para. 124.

256 Para. 125.

257 Reid (1987), p. 115 writes: "Since [Clark] wrote that classical article the devising of lists of criteria for workability has become something of a black art, and Sosnick (1958) in his influential critique of concepts of workable competition codifies 18 such lists.".

258 Para. 124 and 125.

broadly acceptable outcomes. Or, to put it more simply, to regulate so as to achieve broadly acceptable outcomes!

Which Outcomes Did the Court Wish To Promote?

26. Although the Court did clarify that the reference to a "competitive market" in the Code refers to a "workably competitive" market, this clarification provides little guidance as to which outcomes of which competitive markets the regulator is to pursue. The Court has merely excluded a narrow (and arguably unlikely) interpretation of the phrase "competitive market". Having clarified that the phrase "competitive market" refers to the full, broad, concept of workable competition, the Court states that the full exploration of the outcomes of a workable competitive market which are to be replicated, is to be left to the regulator:

> It is not necessary for the purpose of this decision to attempt to explore fully the implications of this in the full understanding and application of s 8.1(b). That is primarily the task of the Regulator within the bounds of the intended meaning of the provision.[259]

27. Nevertheless, the Court did take the opportunity to emphasise certain outcomes of a workably competitive market that it would like to see replicated. The Court focuses on three features of a "workably competitive market":

(a) First, workable competition is a dynamic process: "A workably competitive market is not a fixed and immutable condition with any absolute or precise qualities, but a process which involves rivalrous market behaviour. … As such, a workably competitive market will react over time and according to the nature and degree of various forces that are happening within the market."

(b) Second, there may be temporary departures from static equilibrium conditions: "There may well be a degree of tolerance of changing pressures or unusual circumstances before there is a market reaction. The expert evidence and writings tendered in evidence suggest that a workably competitive market may well tolerate a degree of market power, even over a prolonged period."

(c) Third, efficiency does not necessarily attain "theoretically ideal efficiency": "The underlying theory and expectation of economists, however, is that with workable competition market forces will increase efficiency beyond that which could be achieved in a non-competitive market, although not necessarily achieving theoretically ideal efficiency."

28. Since, it seems to me, this last point is open to misinterpretation, it deserves further discussion. Taken as a stand-alone statement, this sentence seems to imply that one of the outcomes the regulator should seek to replicate is something other than ideal efficiency. Yet, this cannot be the intended meaning of this statement, for the following reasons:

[259] Para. 128.

- First, this conclusion leads directly to nonsensical outcomes. The economist's concept of efficiency is broad and incorporates the welfare of all participants in the market. To state that the regulator should aim for something which involves less-than-ideal efficiency is to imply that the regulator should aim to achieve a sub-optimal outcome or that the regulator should aim for an outcome which involves a lower overall welfare than some other outcome. It seems highly unlikely that the Court would require that (or believe that the drafters of the Code would require that) the regulator should consistently act in an imperfect manner.

- Second, this conclusion seems to contradict other sentences in the decision itself. For example, paragraph 143 states that:

  "A workably competitive market appears to be viewed by the general body of economic opinion as likely, over time, to lead to economic efficiency or at least to greater economic efficiency".[260]

  In paragraph 125, the Court notes that "economists generally consider that competitive markets lead to conditions of economic efficiency".

  The Court does not seem to consider that these statements are in conflict with the statement in paragraph 128 that a workably competitive market would not achieve "theoretically ideal efficiency". Either the Court was unaware of this possible contradiction or, more likely, the Court felt that in some broader sense workable competition achieves economic efficiency, even if it wasn't "the ideal efficiency standard of textbook models".

29. In fact, it seems to me that there is a relatively simple reconciliation of these apparent contradictions in the Court's comments. Given the emphasis in paragraph 128 on workable competition as a process, it seems likely that the Court had in mind (even if not articulated) a possible trade-off between the static and dynamic concepts of efficiency.

30. If we insert the word "static" into the references to "theoretically ideal efficiency", the overall argument of the Court makes sense. Paragraph 125 would then observe that "competitive markets lead to conditions of economic efficiency" but workable competition would "not necessarily fulfil the ideal [static] efficiency standard of textbook models". Paragraph 128 would note that workable competition would not necessarily achieve "theoretically ideal [static] efficiency".

31. This approach would leave open to the regulator the pursuit of economic efficiency (i.e., the pursuit of maximum overall welfare) and would not require the regulator to choose sub-optimal outcomes. Instead, the primary force of the Court's argument is that the regulator should not place undue weight on static concepts of efficiency. Instead, according to the Court, the regulator should place due weight on the dynamic efficiency outcomes of competitive markets – the incentives to take risks, to exploit opportunities and to innovate. This could lead to temporary (or even prolonged)

[260] Para. 143.

deviations from some narrow notions of efficiency, but to the greater good of efficiency overall.[261]

Implications of the Epic Decision

32. In my view, the primary implications of the Epic decision lie not in the Court's interpretation of "competitive market" as "workably competitive" (and therefore, the key issue is not what are the outcomes of a workably competitive market) but rather, the primary implications of the Epic decision lie in the emphasis the Court places on certain outcomes of a competitive market that it would like to see.

33. In my view, the Court, in using the term "workable competition" was not intending to use a narrowly defined concept or a "term of art". Rather the Court was simply seeking to exclude a narrow interpretation of the concept of competitive market. In this respect the Court has not clarified the regulator's task at all (and, has, to an extent, broadened the scope for discretion).

34. Of primary interest, therefore, is the Court's highlighting of certain outcomes. The strong implication is that these are the outcomes which the regulator should seek to replicate. I have noted three or four such outcomes:

(a) First, it seems that the Court envisages that adjustment to a new equilibrium will not always be rapid. As already cited: "There may well be a degree of tolerance of changing pressures or unusual circumstances before there is a market reaction. The expert evidence and writings tendered in evidence suggest that a workably competitive market may well tolerate a degree of market power, even over a prolonged period."[262]

(b) Second, the Court envisages that there may arise a need to compensate for risks taken in the presence of sunk investments: "… in a workably competitive market past investments and risks taken may provide some justification for prices above the efficient level".[263]

(c) Third, the Court seems to acknowledge that, in a workably competitive market asset valuation would be proxied by DORC "The expert evidence indicates that a DORC valuation will usually provide a good proxy for the price that a pipeline would realise had the owner faced workable competition at the time of its sale".[264]

(d) Finally, the Court seems to acknowledge that a workably competitive market must be sustainable in the long run: "The expert evidence … suggested a growing awareness of the long term disadvantages of striking the balance [between the interests of consumers in obtaining low prices and the service provider in receiving high prices] with too

[261] This view can be seen as consistent with the Court's rejection of the interpretation of "competitive market" as "a perfectly competitive market".
[262] Para. 128.
[263] Para. 144.
[264] Para. 164.

great an emphasis on the interest of consumers in securing lower prices, and without due regard to the interest of the service provider in recovering both higher prices and its investment".[265]

35. From our earlier discussion we can see that, in highlighting these outcomes the Court *is* providing clear guidance as to which outcomes of which competitive markets the Court would like to see replicated. In particular:

(a) As we already discussed, an attempt to emulate a competitive market with a rapid adjustment to a new equilibrium level of costs may eliminate the incentive on a regulated firm to invest in cost-reducing effort. A slow adjustment of prices to costs may be a necessary component of incentives for efficiency in a regulatory regime. (But how slow? There is no guidance on this point).

(b) As already noted, in the presence of sunk costs, firms will need to be compensated for any risks that they take. This must involve higher returns in certain states of the world to compensate for lower returns in other states of the world. In fact this "above normal" compensation could persist for some time. (Since this "rent" would persist even in a competitive market, it is not correct to refer to this "above normal" compensation as" monopoly rent").

(c) In emphasising the importance of long-term sustainability the Court is encouraging the regulator to emulate a competitive market which is sustainable (with on-going investment) rather than one which is in decline.

36. I wish to emphasise at this point that, in my view, the Court is *not* advocating that monopoly rents be tolerated or that inefficiency be tolerated. There is no evidence that the Court believes that monopoly rents or inefficiency would persist in a workably competitive market. Both would be competed away.

37. As I argued earlier, the Court is not arguing that a workably competitive market would not be economically efficient. Indeed, in several places they state exactly the opposite. The Court does argue against using a narrow efficiency concept (such as might be implied by "perfect competition").

Conclusion

38. The concept that regulators should replicate the outcomes of competitive markets seems to be widely accepted. It is not so widely understood that this principle is ambiguous in many respects. There are many different competitive markets with quite different properties. The competitive markets principle does not assist the regulator to determine which outcomes of which markets it should emulate.

39. Overall, the Court in the Epic decision seems primarily concerned to exclude a narrow concept of competitive market. In particular, the Court excludes the narrow

[265] Para. 145.

theoretical concept of "perfect competition" to embrace a broader concept of workable competition. Workable competition, like its cousin "effective competition", is not a precise concept or a term of art but simply denotes that state of competition which yields broadly acceptable outcomes. However a very wide range of markets yield broadly acceptable outcomes. This conclusion alone provides virtually no guidance for the regulator.

40. The Court goes on to highlight particular outcomes which it seems to view as important. Within the range of competitive markets, the Court prefers those in which adjustment to equilibrium is not too rapid and in which firms are rewarded for the risk which they bear. This aspect of the Courts decision is useful guidance for regulators.

41. More generally, the Epic case highlights the flaws in the use of the "competitive markets principle" as a legislative guide for regulators. The Code and the Electricity Code already specify a number of other criteria which the regulator is to take into account. It is not clear how much extra value is added by a requirement that the regulator also replicate the unspecified outcomes of an unspecified competitive market.

Appendix: On Workable Competition

42. The concept of workable competition dates to a 1940 article by J M Clark.[266] By 1940 it was widely recognised that very few industries met the theoretical conditions for perfect competition. But, at the same time, this did not automatically imply that in the majority of industries the outcomes were sufficiently undesirable as to demand some form of government intervention. Rather, it seemed that there was a wide range of industries for which the outcomes were broadly acceptable.

43. Clark's concern was to articulate a competition standard which could include those industries for which competition was sufficient to yield broadly acceptable outcomes. A useful standard would have several benefits – it would prevent inappropriate intervention in those markets for which outcomes were already adequate and it would provide a target for policy aimed at fostering competition in those markets for which competition was not adequate.

44. Clark did not define what constituted workable competition. He did emphasise the important element of rivalry:

> Competition is rivalry in selling goods, in which each selling unit normally seeks maximum net revenue, under conditions such that the price or prices each seller can charge are effectively limited by the free option of the buyer to buy from a rival seller or sellers of what we think of as 'the same product', necessitating an effort by each seller to equal or exceed the attractiveness of the others' offerings to a sufficient number of sellers to accomplish the end in view.[267]

45. But, as Clark admits, "this is not a complete definition". Clark also sets out a set of conditions which would determine the character of competition:

1. Extent of standardization of the product;
2. Degree of seller concentration;
3. Method of setting price
4. Extent of market intermediation (e.g., by brokers, salesmen)
5. Extent, type and quality of market information;
6. Spatial distribution of consumers and producers;
7. Responsiveness of actual supply to production;
8. Pattern of long-run costs;
9. Pattern of short-run costs;
10. Flexibility of capacity variation.

46. It was left to others to articulate more fully the characteristics of perfect competition. Sosnick (1958)[268] accepts that the basic notion of "workable competition is to provide a reliable criterion for judging whether a market situation is socially satisfactory". Sosnick provided an exhaustive set of norms for workability under the "structure", "conduct' and "performance" headings, as set out below:

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[266] This Appendix draws heavily on chapter 7 of Reid, Gavin, 1987, *Theories of Industrial Organization*, Basil Blackwell, 1987.
Clark, J.M., 1940, "Towards a concept of workable competition", *American Economic Review*, 30, pp. 241-256.

[267] Clark (1940), p. 243.

[268] Sosnick, S.H., 1958, "A critique of concepts of workable competition", *Quarterly Journal of Economics*, 72, pp. 380-423.

Structure norms:

1. No dominance, and traders as large as economies of scale will permit;
2. Quality differentials which are moderate and sensitive to prices;
3. No impediments to mobility;
4. Reasonable availability of market information;
5. Some uncertainty about response to price cutting;
6. Freedom from legal restraint;
7. Development of new markets and trade contracts.

Conduct norms:

1. Independent rivalry, in pursuit of profit;
2. No shielding of inefficient rivals, suppliers or customers;
3. No unfair, exclusionary, predatory or coercive tactics;
4. No unreasonable discrimination;
5. No misleading sales promotion;
6. Rapid response by buyers to differentials in attributes of products.

Performance norms:

1. Efficient production and distribution;
2. No excessive promotional expenses;
3. Profits sufficient to reward investment, efficiency and innovation;
4. Output consistent with efficient resource allocation;
5. Prices that do not intensify cyclical problems;
6. Quality consistent with consumers' interest;
7. Appropriate exploitation of improved products and techniques;
8. Conservation requirements respected;
9. Sellers responsive to buyers' needs;
10. Entry as free as the industry sensible permits;
11. Regard for national security requirements;
12. Avoidance of excessive political and economic power in few hands;
13. Regard for employees' welfare.

47. Clark's original article discussed a competitive norm which, like the concept of perfect competition is essentially static in character. In later work (1955, 1961)[269] Clark favoured a dynamic concept of competition, along the lines of that advocated by the so-called "Austrian" school of economics. "Subsequently to developing his idea of workable competition … Clark started to rethink his ideas. Clark (1955) began to favour a dynamic view of workability, with the key features of competition that led to social benefit being the capacity to initiate and sustain innovation".[270] In this paper he abandoned the terminology of "workable competition" and instead sought to define useful criteria for what he called "effective competition".

48. Finally, it is worth noting that despite the flurry of interest in "workable competition" in the 1950s, this term is not currently in widespread usage in mainstream economics. There is, for example, no entry in the New Palgrave Dictionary of Economics on workable competition.

[269] Clark J.M., 1955, "Competition: static models and dynamic aspects", *American Economic Review*, 45, pp. 450-462; Clark J.M., 1961, *Competition as a Dynamic Process*, Brookings Institution.

[270] Reid (1987), pp. 134-135.

49. A simple search of the Internet reveals that the related term "effective competition" is in far more widespread current usage. For example, a search of the website of the US Department of Justice (perhaps the world's leading antitrust authority) reveals no (zero) references to "workable competition" and 182 references to "effective competition". The ACCC's website has 289 references to effective competition and only 20 to "workable competition" (all of which, arguably, relate to the Epic decision discussed above). Finally, a search of the European Commission's DG Competition (the leading European Competition Authority) reveals 7 references to workable competition and 1065 to effective competition.

50. In summary, the key points of this appendix are (a) that the concept of workable competition is an attempt to define those markets in which outcomes are broadly acceptable; (b) there seems to be no generally-accepted standard or precise definition of this term; (c) Clark himself went on to develop the related concept of "effective competition" which places more weight on dynamic processes; and (d) the concept of workable competition is not widespread in modern economic usage – the term "effective competition" is far more common.

Attachment 2 Post-tax revenue model

(See attached pdf document for Post-tax revenue model handbook. Associated Excel worksheets can be downloaded from ACCC website at www.accc.gov.au)

Attachment 3 Draft greenfields guideline

(See attached rtf document)

Attachment 4 Regional guideline

(See attached rtf document)

ATTACHMENT 3

Draft greenfields guideline
for
natural gas transmission pipelines

Draft greenfields guideline for natural gas transmission pipelines

A guide to the access regulation framework and options for new natural gas transmission pipeline developments in Australia

June 2002

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Contents

1. Summary

The Australian Competition and Consumer Commission recognises that prospective investors in new pipelines need to understand how the regulatory regime will apply to their investment. It has drafted this guideline showing the alternatives available under the regulatory frameworks provided by the *National Third Party Access Code for Natural Gas Pipeline Systems* (the code) and Part IIIA of the *Trade Practices Act 1974* (TPA).

In light of the circumstances faced by prospective service providers when considering the construction of a greenfields pipeline, the ACCC has prepared this draft guideline to:

- address perceptions of regulatory risk with regard to the application of the regulatory framework and the ACCC's approach to the regulation of greenfields projects
- demonstrate the flexibility of the regulatory framework and the various approaches available for the structure of an access arrangement or access undertaking
- indicate the ACCC's preferred methods for dealing with project specific risks
- assist prospective service providers to evaluate the likely regulatory outcomes for potential or proposed greenfields projects.

For the purposes of this guideline, greenfields natural gas transmission pipeline investments are considered to be new natural gas transmission pipeline projects, the demand for the output of which was previously non-existent. These gas projects are generally acknowledged to be facing greater uncertainties than established investments.

In preparing this guideline the ACCC consulted with all sections of the gas industry and sought the expert views of consultants. The major findings of the consultancies have confirmed:

- the role of foundation contracts in underpinning new investment, including sharing the long-term investment risks between the pipeliner and users

- debt providers' information requirements, to assess all the risks associated with a project. This enables the debt provider to assess the risk profile of the project and determine the amount, and cost, of debt that can be made available to the pipeline developer. Equity providers similarly assess the risk profile of the project to determine their capital contribution, its structure and their required rate of return

- that a capital asset pricing model (CAPM) approach to determining the weighted average cost of capital (WACC) is an appropriate framework and specific (i.e. non-systematic) risks associated with a greenfields pipeline should not lead to an adjustment of beta—which reflects systematic risks only. Any such adjustment would be ad hoc and could lead to significant biases

- project finance techniques and financial engineering/risk management techniques are typically used (or are available) to reduce specific risks or pass such risks onto those willing and able to bear them at least cost

The ACCC acknowledges these findings. Accordingly, this guideline seeks to address these findings in the context of identifying the various risk categories a greenfields pipeline project is likely to face, and also to provide guidance on how the provisions of the existing regulatory framework can help a prospective investor address and mitigate relevant risks. These include:

- initial capital base of new pipelines, under the code, must be based on actual cost.
- the role of foundation contracts and the preservation of contracts in existence before and subsequent to an access regime
- incentives with respect to demand forecasting and linkages with benefit sharing thresholds. This facilitates pipeliner certainty in that there will be no intra-period re-assessment of forecasts while retaining the option to unilaterally seek a review at any time of an access arrangement in the event that its circumstances materially change
- derivation of reference tariffs is based on forecast volumes, hence the pipeliner is insulated from volume risks (with respect to cost recovery) and incentives for building spare capacity.
- competitive tender processes as a means for determining reference tariffs
- benefit sharing mechanisms—which would provide the service provider with certainty from the outset—regarding the nature and effect of any benefit sharing and at what point it will commence
- term of the regulatory period is not mandated (though subject to regulatory consideration)
- CPI-X incentive mechanisms also alleviate a pipeliner's inflation risk
- depreciation schedules—being the mechanism by which pipeline investors recover the costs of an investment—can be adopted that best meet the service provider's objectives to optimise the use of its pipeline, subject to the requirement that a regulated asset is fully depreciated once, and only once, over its economic life. For example, economic depreciation effectively allows for the carry forward of losses in the early years of operation
- fixed principles, which provide a means of establishing certain aspects (structural elements) of regulatory certainty across access arrangement periods.

Background to industry development and regulation

Despite some criticism of the code it is useful to note that it was designed—with industry input—to facilitate a fair degree of flexibility for service providers in formulating an access arrangement for regulatory consideration. This flexibility provides a range of options for prospective service providers to deal with the unique risks associated with greenfields investments. Comprehensive examples are included in the appendixes to this guideline that illustrate how the aforementioned provisions might be applied in practice by a prospective service provider. It should be noted that these examples are not intended to be exhaustive and, subject to meeting the

requirements of the regulatory framework, project proponents are encouraged to develop variants or alternatives that best meet their unique circumstances.

A significant level of investment has been undertaken in gas infrastructure since the Gas Code was introduced and further investments are currently proposed. Since 1995 more than $1 billion has been invested in upstream, transmission and distribution assets each year. Moreover, according to the Australian Pipeline Industry Association, total transmission pipeline infrastructure has grown from 9000 kilometres in 1989 to over 17 000 kilometres in 2001.[1] The AGA notes that it expects average annual growth in demand for gas to be 4.3 per cent until 2014-15. Gas is currently 17.7 per cent of the total energy supplied in Australia. The Australian Gas Association (AGA) expects this to grow to 22 per cent by 2005 and to 28 per cent by 2014–15.[2]

However, despite the substantial investment in new infrastructure in the energy sectors, concerns have been raised about whether the relevant codes can adequately address the specific needs of a greenfields investment. Accordingly, the ACCC is conscious of the need to:

- balance the interests of users and investors
- provide incentives for long term efficient investment
- set prices that track efficient costs as closely as possible.

In making regulatory decisions the ACCC must establish an appropriate rate of return. In doing so, balance must be achieved between the needs of service providers and users. The perceived short term gains of reducing prices for infrastructure services must be balanced with the ongoing viability of the business and the industry as a whole. This includes assessing access proposals (and not just a rate of return) for a business that will provide the appropriate incentives, and accommodate new efficient investment in infrastructure. Only then will long term efficiencies arise and benefit the economy.

The ACCC's perception is that the code offers a degree of flexibility that is yet to be fully realised by the pipeline industry. The ACCC also regards access undertakings under Part IIIA as containing a significant level of flexibility. Regulation under Part IIIA may be regarded by service providers as an alternative to regulation under the code. The ACCC's current guide to Part IIIA outlines the provisions and requirements of the Trade Practices Act.

While prescribing a range of matters that the regulator is required to consider, the Gas Code also provides a number of provisions and options for prospective regulated greenfields pipelines that can address any uncertainty regarding the application of the regulatory regime. The onus is on the prospective service provider to submit an

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[1] Australian Pipeline Industry Association, *Business Plan 2002–2005*.

[2] Australian Gas Association, Gas Industry Development Strategy 2000–2015.

access arrangement to the ACCC for assessment that complies with the objectives of the Gas Code.

The Gas Code recognises that to encourage investment, a prospective service provider should be given the opportunity to reap some of the returns that exceed the expected level where those returns are attributable to the efforts of the service provider. Often referred to as the 'blue sky' potential of the pipeline such an approach requires regulatory certainty about the treatment of any greater than normal returns, if realised, in the initial regulatory period/s. The inclusion of an incentive mechanism in an access arrangement (or access undertaking) is an important component of a service provider's regulatory framework. The ACCC encourages service providers to develop mechanisms that will best suit their particular needs.

Without constraining the intentions of the Gas Code in this regard, the challenge for regulators is to assess access regime proposals to ensure that they establish fair and reasonable conditions of access for both service providers and users in a manner that preserves the service provider's economic incentives to fully utilise its assets and develop its business. The access regime must also ensure the abuse of monopoly power is prevented.

It is intended that this guideline will therefore help achieve greater certainty through greater transparency and resolve some of the reasonable concerns that have been raised about the difficulties of developing new pipelines.

Finally, it is important to note that regulation of gas transmission infrastructure in Australia is not presumed as a necessary condition precedent for the effective functioning and development of natural gas markets in Australia. A number of tests must be satisfied before a pipeline, or prospective pipeline, is subject to the requirements of the regulatory framework. Accordingly, the ACCC is only concerned with the regulation of natural gas transmission pipelines that either meet the coverage tests under the Gas Code or are subject to an access undertaking or declaration under Part IIIA of the Trade Practices Act.

In Australia the National Competition Council is responsible for making coverage and declaration recommendations.

Nevertheless, some service providers may perceive benefits in securing certainty about the application of the regulatory framework to their particular assets at the outset.

2. Introduction

Despite the substantial investment in new infrastructure in the energy sectors, concerns have been raised about whether the regulatory framework can adequately address the specific needs of a greenfields investment. The ACCC is conscious of the need to:

- balance the interests of users and investors
- provide incentives for long term efficient investment
- set prices that track efficient costs as closely as possible.

The ACCC recognises that prospective investors in new pipelines need to understand how the regulatory regime will apply to their investment. The ACCC has drafted this guideline to show what alternatives are available under the regulatory frameworks of the *National Third Party Access Code for Natural Gas Pipeline Systems* and Part IIIA of the *Trade Practices Act 1974*.

The intention of this guideline is to help achieve greater certainty through greater transparency and to resolve some of the concerns that have been raised about the difficulties of developing new pipelines.

While each pipeline throughout Australia is likely to face unique and differing levels of risk, greenfields pipeline[3] projects are generally acknowledged to face greater uncertainties than established pipelines. For example, a new pipeline without significant foundation contracts proposing to supply gas to a new or immature market, faces greater uncertainty regarding future demand than a 20-year old pipeline that is fully contracted and supplying to a well established customer base. The growth in future demand for a new pipeline can often be dependent upon a number of factors, including other new projects securing funding and remaining operational (e.g. a fertiliser production plant or a gas fired generator) and/or the rate at which users convert from other fuels to natural gas.

In light of the circumstances faced by prospective service providers when considering the construction of a greenfields pipeline, the ACCC has produced this guideline to:

- address perceptions of regulatory risk with regard to the application of the regulatory framework and the ACCC's approach to the regulation of greenfields projects

[3] For the purposes of this guideline, a greenfields pipeline is generally considered to be a new natural gas transmission pipeline project, the demand for the output of which was previously non-existent.

- demonstrate the flexibility of the regulatory framework[4] and the various approaches available for the structure of an access arrangement or access undertaking
- indicate the ACCC's preferred methods for dealing with project specific risks
- assist prospective service providers to evaluate the likely regulatory outcomes for potential or proposed greenfields projects.

This guideline outlines the flexibility available to a prospective service provider when considering the submission of either an access undertaking or an access arrangement. This guideline is not intended to be exhaustive and the ACCC is receptive to considering alternative methods, provided that any proposed approach is consistent with the principles of the National Third Party Access Code for Natural Gas Transmission Pipelines or, in the case of an access undertaking, Part IIIA of the Trade Practices Act.

In preparing this guideline the ACCC consulted with industry, which included hosting a roundtable discussion in November 2001 with representatives from all sections of the gas industry and regulatory staff. Following the input received from the roundtable discussions the ACCC sought the expert views of:

- Macquarie Bank, on the issues relevant to debt and equity providers.[5]
- Messrs Kevin Davis and John Handley, on the appropriate cost of capital.
- National Economic Research Associates, on the role of foundation contracts and related terms and conditions relevant to greenfields natural gas pipeline projects.

The key findings of these consultancies are summarised at appendix 5. Copies of the consultancies are also available at the ACCC's website.[6]

Prospective service providers are encouraged to consult with the ACCC when developing an access proposal. However, it is ultimately the service provider's responsibility to design an access proposal that best meets its unique needs and circumstances, while complying with the principles of the national access regime. The ACCC can assist prospective service providers with a preliminary non-binding view on a proposed access arrangement or undertaking; however, for it to provide a well considered response, a sufficient amount of relevant and useful information will be necessary. Prospective service provider consultation with the ACCC is discussed in detail in section 7.

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[4] The regulatory framework for natural gas transmission pipelines in Australia is comprised of the National Third Party Access Code for Natural Gas Transmission Pipelines and Part IIIA of the *Trade Practices Act 1974*.

[5] The ACCC recommends that readers refer to the consultancy report, including the Executive Summary, for a description of the terms of reference for the report.

[6] <http://www.accc.gov.au/gas>

The guideline is structured as follows:

Section 1. Summary

Section 2. Introduction

Section 3. Provides an overview of the regulatory framework and the bases for determining when a prospective pipeline is likely to be subject to regulation or can be voluntarily submitted for a regulatory determination.

Section 4. Outlines the major risk categories faced by a greenfields pipeline and considerations for mitigating those risks.

Section 5. Addresses the range of risk mitigation options available in relation to tariff setting, downside risk, the role of foundation contracts and contractual commitments and determination of the regulatory asset base.

Section 6. Addresses managing uncertainty in relation to demand forecasting and securing the potential to reap blue-sky opportunities.

Section 7. Discusses the provision of information and regulatory consultation considerations.

Appendix 1. Example of the derivation of expected demand and expected return forecasts when facing uncertainty.

Appendix 2. Example of an adjustment to the initial capital base to reflect actual costs and the effect/s on reference tariffs.

Appendix 3. Example of determining benefit sharing when demand exceeds a pre-set threshold and effect on revenues, profits and tariffs.

Appendix 4. Summary of the consultancies undertaken.

Appendix 5. Summary of code provisions that facilitate regulatory certainty.

Appendix 6. Glossary.

Appendix 7. Related publications.

Copies of this draft Greenfields guideline for natural gas transmission pipelines and related consultancies are available on the ACCC's website at: <http://www.accc.gov.au/gas>

Following the release of the draft guideline the ACCC will hold a public forum at which interested parties can raise any issues or make comments on the guideline. Details of the public forum will be well publicised in the major daily press.

Any comments on the draft guideline should be addressed to the following email address: gas@accc.gov.au:

Alternatively written comments should be addressed to:

Ms Kanwaljit Kaur
General Manager
Regulatory Affairs Division—Gas Group
PO Box 1199
DICKSON ACT 2602

3. The regulatory framework

Essentially, a prospective service provider has three possible alternatives regarding the regulatory environment when considering a greenfields pipeline project:

(i) the pipeline becomes 'covered' under the *National Third Party Access Code for Natural Gas Pipeline Systems*

(ii) an access undertaking in relation to the pipeline is submitted by the service provider under Part IIIA of the Trade Practices Act

(iii) the pipeline is unregulated.

Each of these alternatives is discussed further below.

A prospective service provider may choose to be regulated from the outset for a number of reasons depending on the environment and circumstances facing the pipeline. For example, a service provider may prefer certainty from the outset in relation to the application of elements of the regulatory regime or there may be strong reason to believe that coverage will be sought (and approved) on the pipeline in question.

3.1 Role of the National Competition Council

Part IIA of the Trade Practices Act sets outs the functions of the National Competition Council (NCC).[7] The NCC is an independent statutory council that has a function in recommending to the federal Treasurer and to the responsible State and Territory Ministers the declaration of services under the essential facilities provisions of Part IIIA.

Part IIIA provides for existing access regimes, such as the code, to be recognised as 'effective' by the relevant Minister (on recommendation from the NCC). As at April 2002 the respective access regimes established by the code and its supporting legislation have been certified effective in South Australia, Western Australia, New South Wales, Victoria, the ACT and NT, with a decision pending on an application from Queensland.

Alternatively, in the absence of an access regime that has been certified as effective under Part IIIA any person (for example a third party who may have been unsuccessful in privately negotiating access on an unregulated pipeline) may apply to the NCC for a recommendation to the relevant Minister, that the service be 'declared'.[8]

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[7] National Competition Council website can be found at <http://www.ncc.gov.au>.

[8] ACCC, Access regime—a guide to Part IIIA of the Trade Practices Act, November 1995.

Additionally, under the code, the NCC has a role in making recommendations to the relevant Minister whether or not a pipeline should be 'covered'.[9]

3.2 Coverage under the code

The code establishes a national access regime for natural gas pipelines. It sets out the rights and obligations of service providers, pipeline users and access seekers. It includes coverage rules, the operation and content of access arrangements, ring fencing arrangements, information requirements, dispute resolution and pricing principles. Under the code the ACCC is responsible for the regulation of all covered transmission pipelines in Australia, with the exception of Western Australia.[10]

Once a pipeline becomes covered it is subject to the principles set out in the code. There are three ways in which a greenfields pipeline may become covered.

- A service provider or prospective service provider can volunteer that a pipeline be subject to the provisions of the code by proposing an access arrangement to the regulator for approval. Following the regulator's approval the pipeline is covered from the date that the access arrangement becomes effective until any specified expiry date (sections 1.20 and 2.3 of the code).
- A pipeline is automatically covered if it is subject to a competitive tendering process approved by the regulator (section 1.21).
- Any person may make an application to the NCC requesting that a pipeline be covered (section 1.3). The NCC subsequently provides a recommendation to the relevant Minister, who makes a decision on the matter. The criteria for determining whether a pipeline should be covered is set out in section 1.9 of the code.

Before deciding on a regulatory approach, if any, a prospective service provider has the option to seek a (non-binding) opinion from the NCC[11] on whether a proposed pipeline would meet the criteria for coverage in section 1.9.

Flexibility of the code

The ACCC considers that the code has been drafted with the clear intention of accommodating access arrangements for prospective pipelines. This view is supported by the findings of National Economic Research Associates (NERA) in its

[9] Refer code section 1.2

[10] The Office of Gas Access Regulation (OffGAR) is the responsible regulator for transmission and distribution of natural gas pipelines in Western Australia.

[11] Refer code section 1.22

analysis that the code serves as an effective access regime which helps, rather than hinders, the expansion of an integrated gas pipeline infrastructure in Australia.[12]

While prescribing a range of matters that the regulator is required to consider, the code provides a number of provisions and options for prospective regulated greenfields pipelines that can mitigate uncertainty regarding the application of the regulatory regime. These options, and illustrative examples, are set out in more detail in the following sections.

3.3 Submission of a Part IIIA undertaking

Part IIIA provides a legal regime to facilitate access to the services of certain facilities of national significance. Under Part IIIA, service providers can submit access undertakings to the ACCC specifying the terms on which access will be made available to third parties.

Section 44ZZA of the TPA sets out the matters the ACCC must have regard to in deciding whether to accept an undertaking:

- the legitimate business interests of the provider
- the public interest
- the interests of potential third party users
- whether there is an existing access regime
- any other matters the ACCC thinks relevant.

The open ended nature of the criteria gives the prospective service provider considerable scope to design and implement an undertaking according to its needs and gives the ACCC flexibility in analysing and assessing the undertaking. At the same time such flexibility may create uncertainty about the ACCC's approach and could lead to concerns over perceived inconsistencies between undertakings. To mitigate these concerns the ACCC has a guideline, *Access undertakings*, for the submission of an access undertaking.[13]

The undertakings guideline is structured to help prospective service providers and other interested parties understand what is involved in having an access undertaking accepted by the ACCC. It outlines:

- procedures for assessing and lodging access undertakings;
- the legislative criteria for assessing undertakings and the main factors that the ACCC will take into account in applying them

[12] National Economic Research Associates, *Natural Gas Pipeline Access Regulation—Report for BHP*, 31 May 2001, p. 2.

[13] ACCC, Access undertakings—a guide to Part IIIA of the Trade Practices Act, September 1999.

- guidelines on what an owner/operator of a facility should include in an undertaking.

While the legislative criteria take precedence over the ACCC's published guidelines, the guidelines describe the ACCC's considered view on how an access undertaking should be approached. Accordingly, the ACCC, in ensuring careful consideration of the merits of an undertaking proposal, requires owners/operators to provide sound reasoning and justification should they wish to depart from the approach foreshadowed in the guideline.

Prospective service providers considering the submission of a Part IIIA undertaking should consult the *Access undertakings* guideline in conjunction with this guideline when considering the content of an undertaking.

3.4 Similarities between regimes

While the code may appear more prescriptive than Part IIIA, both are essentially based on the same principles.

Part IIIA was the basis upon which the code was developed and the intention was that an 'access arrangement would be similar in many respects to an undertaking under Part IIIA'[14]. Further, the code was specifically designed to address access to natural gas pipelines and is a major component of access regimes that have been certified as effective in a number of jurisdictions.

Given this, it is not unreasonable that the ACCC would look to the code for guidance when assessing a proposed access undertaking. The ACCC considers that the code reflects necessary principles that are likely to be relevant to any consideration of an access undertaking. Therefore, the ACCC recommends that prospective service providers provide a sound rationale should they seek to depart from the principles contained in the code.

The *Access undertakings* guideline indicates that whatever pricing methodology is chosen, it would require reference tariffs to be 'based on the efficient costs of providing reference services' and 'prices should converge towards efficient costs over time'. In a similar vein the reference tariff principles given in section 8 of the code specify, among other things, that a reference tariff policy should be designed to 'improve efficiency and to promote efficient growth of the gas market', 'replicate the outcome of a competitive market' and 'be efficient in level and structure'.

3.4.1 Potential for regulatory overlap

Part IIIA provides for existing access regimes, such as the code, to be recognised as 'effective' by the relevant Minister (on recommendation from the NCC). The services covered by jurisdictional gas access regimes that have been recognised as 'effective'

[14] National Third Party Access Code for Natural Gas Pipeline Systems, November 1997, p. 1.

under s. 44N of the TPA can not subsequently be the subject of a declaration application to the NCC.

However Part IIIA does not explicitly state that certification of an access regime as 'effective' also excludes the operation of an undertaking. Therefore, technically, there is a possibility of regulatory overlap arising. That is, a particular pipeline could potentially be the subject of an access arrangement and an access undertaking at the same time.

In assessing undertakings the ACCC will establish whether there is an existing access regime and if so whether an undertaking is necessary.[15] Given the similarities between the regimes and additional costs of implementing two regimes simultaneously, the ACCC would be unwilling to accept an undertaking where an approved access arrangement is already in place unless there are strong reasons for doing so.

Conversely, it is possible that an application is made to the NCC for coverage of a pipeline that already has an existing access undertaking in place. In its assessment of the application for coverage of the Eastern Gas Pipeline (EGP), the NCC indicated that the presence of an access undertaking should be taken into consideration when assessing the potential benefits of coverage under the code. At the time Duke Energy International had lodged a draft undertaking for the EGP with the ACCC for assessment. As the ACCC had not made a decision regarding the undertaking it was difficult for the NCC to place much weight on the undertaking.[16] However, the NCC has indicated that if an approved access undertaking is in place, it is unlikely that a recommendation for coverage will be made.

Section 1.9(a) of the code requires the NCC (and decision-maker) to be satisfied that competition would be promoted in a dependent market by regulation under the code. This is to be compared with the likely state of competition without regulation under the code (EGP decision). If the pipeline is regulated by an undertaking, it is unlikely that regulation under the code would promote competition, so criterion (a) will not be met.

This interpretation of section 1.9(a) of the code is further supported by a recent decision of the designated Minister to accept the recommendation of the NCC and not declare the rail network services provided by Freight Australia which were the subject of an application for declaration. The basis for this decision was that declaration would not have promoted competition given that access was already provided under

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[15] ACCC, Access undertakings—a guide to Part IIIA of the Trade Practices Act, September 1999, pp. 15, 16.

[16] NCC, Final recommendation—Application for coverage of Eastern Gas Pipeline, p. 17.

the Victorian access regime.[17] Accordingly s. 44H(4)(a) of the TPA was not met. Section 1.9(a) of the code is essentially the same as s. 44H(4)(a).

A prospective service provider may request an opinion from the NCC on whether a proposed pipeline would meet the criteria for coverage in section 1.9.[18] Prospective service providers considering an access undertaking are also encouraged to consult with the ACCC in advance of lodgment.[19]

3.5 Unregulated pipelines

A prospective service provider also has the option to elect, on the basis of its own commercial judgment, with or without consultation with regulatory authorities, to build an unregulated greenfields pipeline. For example, a prospective service provider may be of the view that the pipeline would be too small to meet the tests under Part IIIA or the code, or that the costs of imposing regulation would outweigh the benefits.

It is important to note that a service provider's election not to provide a voluntary access regime does not preclude access being sought by some other party in the future. As noted earlier, under the code any person may at any time make an application to the NCC requesting that a pipeline be covered. If, based on the NCC recommendation, the relevant Minister decides that the pipeline should be covered, the service provider would then be required to submit an access arrangement for the pipeline. Therefore, while a prospective service provider may consider regulation of a pipeline inappropriate or unnecessary, it is possible that coverage of the pipeline may be sought some time in the future by a third party.

In the absence of an access regime that has been certified as effective under Part IIIA any person (for example a third party who may have been unsuccessful in privately negotiating access on an unregulated pipeline) may apply to the NCC for a recommendation to the relevant minister, that the service be declared.[20] If successful the terms and conditions of access to a declared service are to be negotiated by the parties in the first instance, with the ACCC being empowered to arbitrate access disputes notified to it, having regard to the arbitration criteria specified in the TPA.[21]

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[17] I Campbell (Parliamentary Secretary to the Treasurer), Statement of decision and reasons concerning the application for declaration of rail network services provided by Freight Australia, 1 February 2002.

[18] Refer code section 1.22

[19] ACCC, Access undertakings—a guide to Part IIIA of the Trade Practices Act, September 1999, p. 64.

[20] ACCC, Access regime—a guide to Part IIIA of the Trade Practices Act, November 1995.

[21] ibid.

4. Risks faced by greenfields pipelines

The ACCC acknowledges that prospective greenfields pipeline investors may face a different risk profile to an incumbent pipeline operator. Although some risks may not necessarily be unique to the prospective service provider, the overall level of project risk may be greater for a greenfields pipeline project than it is for an established pipeline serving established customers.

Clearly there is a myriad of individual risk elements that require identification and management in any greenfields pipeline proposal. However, it is recognised that, in general terms, greenfields pipelines face the following broad risk categories during the planning, construction and operational phases of a pipeline's life.

(a) Financing phase e.g.:

- procuring materials that might be sourced in foreign currency, noting such financial risks may occur in either, or both, the construction and operational phases of greenfields pipeline projects.

(b) Construction and completion phases in the development of a greenfields pipeline e.g.:

- completion delay because of weather or other factors, significant cost over/under-runs, timing requirements that may necessitate a greenfields pipeline committing substantial capital well ahead of final approvals.

(c) Operational phase e.g.:

- unexpected failure and maintenance resulting from a hostile environment and loss of transportation tariff revenue.

(d) Demand forecasting e.g.:

- the uncertainties associated with forecasting demand volumes, likely market growth factors and realisable revenues etc.

With respect to a proposed pipeline, it is recognised that the aggregate potential effects of such project risks need to be considered in any greenfields pipeline evaluation, both for the purposes of the greenfields pipeline assessment of whether or not to proceed with an investment, and for the purposes of determining reference tariffs. In addressing risk it is important to note the different contexts in which the term is used. Namely systematic risk which is compensated for in the weighted average cost of capital (WACC) in the regulatory framework, as compared to the more generic concept of referring to the possibility of an adverse event.

4.1 The treatment of risk in the regulatory framework

Whether assessing an access proposal under the code or Part IIIA, the ACCC is required to make a determination that balances the legitimate interests of the service provider, existing users, potential third party access seekers and the broader public interest. The legitimate interests of the service provider include providing a rate of return that is commensurate with prevailing conditions in the market for funds and with the commercial risk associated with providing the reference service.

Notwithstanding the development risks a greenfields proponent faces (which are addressed below), it is well established in the finance literature that the appropriate measure of risk for determining the rate of return on a project (whether greenfields or mature) is the systematic risk of a project and not its total risk.[22]

As noted by NERA[23], this approach is consistent with that adopted by the Federal Energy Regulatory Commission (FERC) in the US whereby no additional allowance is made in setting the allowed rate of return for the 'risk' a pipeline service provider faces in needing to fill capacity or sign long-term contracts.

To the extent that it may occur in regulated transmission pipelines, 'asymmetric risk', which is where either the downside risk or the upside risk dominates; over time resulting in a net cost or a net benefit respectively, can be addressed in the regulatory framework. Clearly asymmetric risk does not solely affect either service providers or users but depends on the nature of the risk categories being considered.

Risk can be divided into two categories: systematic (non-diversifiable), and non-systematic (diversifiable) risk. Systematic risks are the market-related risks faced by an investor irrespective of the industry. Examples are the risk of political upheavals and economic up-turn or down-turn.

Compensation for systematic risk is made though the market-risk premium and beta factors found in the Capital Asset Pricing Model (CAPM). The CAPM requires compensation for systematic risk only, as firm-specific risk can be eliminated through diversification. The equity beta is 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). With the market average being equal to one, an equity beta of less than 1 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.

Where an equity beta is calculated for a particular company, it only applies to the particular capital structure of the firm. A change in the gearing will change the level of financial risk borne by the equity holders. Hence the equity beta will change. It is possible to derive the beta that would apply if the firm were financed with 100 per cent equity, known as the 'asset' or 'unlevered beta'. This means companies with different capital structures can be compared. The analyst can then calculate the equivalent equity beta for any level of gearing desired, known as 're-levering' the asset beta.

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

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[22] K Davis & J Handley, Report on cost of capital for greenfields investment in pipelines, March 2002.

[23] National Economic Research Associates, Regulation of tariffs for gas transportation in a case of 'competing' pipelines: evaluation of five scenarios, October 2000.

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, specific risk is not reflected in the equity beta parameter of the CAPM.

While other asset pricing models involving additional risk factors have been developed in the literature, the CAPM is currently still considered to be the dominant approach adopted in practice for estimating required rates of return.[24] The ACCC considers that the CAPM is an appropriate framework for assessing the WACC (weighted average cost of capital) facing a greenfields natural gas transmission pipeline. Accordingly the integrity of the CAPM model should be maintained, in that it only recognises risks of a systematic or market related nature. The ACCC will not consider variations to the CAPM that are not purely of a systematic type. Specific, i.e. non-systematic, risks associated with a greenfields pipeline should not lead to an adjustment of beta—which reflects systematic risks only. Any such adjustment would be ad hoc and could lead to significant bias.[25]

A matter of significant debate in the ACCC's assessment of the Victorian access arrangement was the treatment of specific (diversifiable) risk. As discussed 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. The ACCC indicated in its *Draft Statement of Regulatory Principles* that this is the approach the ACCC will normally adopt with respect to identified and quantified specific risks[26] and has done so in all subsequent decisions. This is consistent with the former Office of the Regulator General's (now the Victorian Essential Services Commission) 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 earn its costs of capital on average, taking account of all possible events.'*[27]

The ACCC understands that prospective service providers will need to undertake detailed market surveys, technical and financial analysis of a range of matters in the project evaluation phase of a greenfields pipeline and that a number of parties involved in such a project will need to assess such data. For example, as noted in

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[24] K Davis & J Handley, Report on cost of capital for greenfields investment in pipelines, March 2002.

[25] ibid.

[26] ACCC, Draft Statement of Principles for the Regulation of Transmission Revenues, 27 May 1999, p. 79.

[27] Office of the Regulator General, *2003 Review of Gas Access Arrangements, Consultation Paper No 1*, p.60, May 2001.

Standard and Poor's criteria for the project financing of pipelines[28] an in-depth analysis of the type and nature of the contracts in place between a service provider and users is required to be undertaken to assess the credit profile of a pipeline. Financiers similarly need to conduct a comprehensive due diligence of the market survey assessments and projections undertaken for a pipeline financing proposal to assess the overall risk and viability of the funding proposition sought.[29]

Regulatory decision making processes similarly need to consider such data. However, in the regulation of gas transmission pipelines the ACCC does not conduct traditional rate of return regulation. Rather, it adopts an incentive regime that encourages the regulated business to outperform the benchmarked return (as determined by the reference tariff for the 'reference service', forecast costs and forecast demand) for the regulatory period. This regime provides incentive mechanisms by encouraging service providers to reduce their costs in any given regulatory period and maximise the efficient use of the infrastructure. If the provider realises cost savings in that period, while maintaining a given level of service standards, it may be able to retain those savings. A service provider can also earn above benchmark returns by increasing its customer usage above forecast demand.

The ACCC's post tax revenue model[30] provides prospective service providers with an interactive working example that demonstrates the application of these principles to facilitate compensation for systematic risks and the relevant operations and maintenance, depreciation and net tax payable costs incurred over the regulatory periods.

4.2 Financing phase

Consistent with the benchmarking approach outlined above and with the objectives of the code and Part IIIA, the ACCC considers that when legitimate costs are incurred as a result of, or in an attempt to mitigate, financial risk then such costs can be appropriately recognised and compensated for in the regulatory regime. Clearly compensation for such costs can only apply where they are of a non-systematic nature and are not otherwise compensated for, eg where such costs are not provided for as an element of the costs to which the incentive based benchmarking approach applies.

For example, a project might procure materials from overseas and manage its financial risk through the use of appropriate hedging or swaps arrangements. If the related costs are attributable to construction related costs then such costs could be

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[28] Standard and Poor's, Infrastructure finance—Criteria for project financing of pipelines, 2001.

[29] Macquarie Bank Limited, Issues for debt and equity providers in assessing greenfields gas pipelines, May 2002.

[30] ACCC, *Post-tax revenue handbook*, October 2001. This can be found on the ACCC's website at <http://www.accc.gov.au/gas/>.

capitalised and reflected in the initial capital base (ICB) of the asset. Similarly, for variations in capital costs that might occur as a result of changes in the exchange rate, the code provides for the use of actual cost to value the capital base for new pipelines.

4.3 Construction phase

The ACCC recognises that in the planning and construction phases of a greenfields pipeline there is a range of risk elements common to any construction contract, irrespective of whether the construction is related to an unregulated or regulated service.

For greenfields pipelines that are to be subject to a regulatory regime, the code provides scope for insulating a prospective greenfields pipeline from construction cost risk, in that cost overruns will be included in the ICB as a component of 'actual capital cost'[31] and, subject to the provisions of section 8.9 of the code, there is no reassessment of actual cost in subsequent regulatory reviews.[32]

Similarly, Part IIIA requires the ACCC to have regard to the legitimate business interests of the service provider, which includes the ongoing viability of services covered by the undertaking and commercial returns on investment in the facility.

One of the aims of both Part IIIA and the code is to promote efficiency. Application of Part IIIA or the code does not provide for compensation to prospective service providers for any damages arising from failure, on the part of the service provider, to meet contractual obligations to its customers. Therefore, in the event that a delay is attributable to a prospective service provider this should not create the perverse situation whereby any resulting costs are ultimately passed on to users as a component of the reference tariff(s).

Accordingly, the ACCC does not consider that it is the intention of Part IIIA or the code to compensate a prospective service provider for risks that can be addressed through normal commercial practice, such as the management of construction risks via contractual or other arrangements for gain/pain sharing between owners, prime and sub-contractors. For example:

- regarding possible timing overruns, the ACCC notes that in fixed price or cost plus contracts, accepted practices provide for back to back provisions in such contractual arrangements, or
- alternatively, alliance-contracting principles provide a range of options and incentives for all contracting parties to best manage project risks.

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[31] Refer code section 8.12.

[32] Refer code section 8.14. Note this is subject to the provisions of section 8.9 with respect to new facilities investment, recoverable portion, depreciation and redundant capital.

For example, a prospective service provider might enter into a contractual commitment with a prospective user that incorporated penalties for failure to deliver gas by a pre-agreed date. Then, in the event of a failure to deliver by that date, it would clearly be an undesirable outcome if the regulatory framework effectively allowed the service provider to recoup those penalty payments by reflecting them in the capital base. The effect of this would be to ultimately pass those costs through to those same users.

Such contractual management arrangements in construction contracts are not an explicit component of the regulatory regime and are entirely within the remit of the prospective service provider. Further, a prospective service provider can insulate itself from claims by foundation customers by providing flexibility in foundation contracts. Where delays are not attributable to the prospective service provider, the ACCC would anticipate that a prudent service provider would seek to recover any damages arising under its contractual arrangements.

This approach is consistent with the findings of Davis and Handley who noted:[33]

> Project finance techniques and financial engineering/risk management techniques are typically used (or are available) to reduce specific risks or pass such risks onto those willing and able to bear them at least cost. Provided that the capital base concept adopted for use in regulatory price determination reflects the cost of such risk transfer, or that the cash flows required to insure/hedge such risks are reflected in operating costs, no further adjustment for risk would appear to be warranted.

The ACCC recognises that time lags are involved in construction before cash inflows are realised. Davis and Handley[34] have advocated that project viability requires that those outlays should be compounded at the required rate of return in determining the cost base of the project.[35] This approach is analogous to the application of the existing provisions of the code regarding the treatment of a speculative investment fund[36] (as opposed to a greenfields type project). The ACCC acknowledges this approach and, consistent with the ACCC's *Draft Statement of Principles for the Regulation of Transmission Revenues*[37], considers that it can be accommodated within the scope of section 8.12 of the code.

The approaches outlined above also ensure the following objectives are met:

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[33] Davis & Handley, loc.cit.

[34] ibid.

[35] For example, if a project involves an outlay of $1 at date 0, has a required rate of return of r, and generates no cash flows until date 2, the required cash inflow at date 2 is $\$1(1+r)^2$ if the project is to have a zero NPV. If target cash flows at date 2 are to be determined at date 1, the appropriate capital base for use at that date is $\$1(1+r)$.

[36] Refer code section 8.19(b).

[37] ACCC, Draft Statement of Principles for the Regulation of Transmission Revenues, 27 May 1999, p. xii.

- maintaining the economic and financial incentives for the prospective service provider to manage construction in the most efficient manner while ensuring the proper recognition of, and compensation for, those costs prudently incurred
- avoiding the imposition of costs on users for risks that can be adequately addressed during the construction phase and bear no direct relationship to the cost of service for gas haulage
- ensuring risks that are ordinarily and best managed via contractual arrangements continue to be managed in that manner
- ensuring that a prospective greenfields pipeline does not receive compensation that would be additional to what it could receive in a competitive environment.

The provisions for managing construction costs under the code are significantly more flexible and accommodating than in some overseas jurisdictions. For example, in the US the FERC, in its statement of policy, places the financial responsibility for new greenfields gas pipeline development on the prospective service provider. Similarly, the risk of construction cost overruns rest with the prospective service provider, unless it is apportioned between it and shippers in their contracts. Additionally, the prospective service provider is left responsible for the costs of under-utilised capacity and cost overruns.

As part of the FERC's regulatory application process, a prospective service provider has to submit estimated construction cost data for the pipeline project. The FERC will approve transportation tariffs for the prospective service provider taking these construction data into account, along with other relevant cost data and information. Thus, to the extent that the prospective service provider incurs greater construction costs than budgeted for in its submission to the FERC, the prospective service provider will not be permitted to recover these additional costs from shippers through higher tariffs.

However, the FERC has approved a mechanism that provides incentive for prospective service providers to remain within the estimated target costs of a specific pipeline construction project. Under this incentive mechanism the costs of the expansion are subject to a project cost containment mechanism (PCCM). The PCCM establishes a target cost of each new pipeline project. If a prospective service provider manages to carry out the pipeline project for less than the target cost it will share its savings with shippers. If the actual construction costs are higher than the target costs, the prospective service provider has to bear most of these cost overruns.[38]

4.4 Operational phase

Generally, regardless of whether a pipeline is a greenfields investment or a well-established incumbent, it is likely that it faces some form of operational risk. The

[38] National Economic Research Associates, Foundation contracts and 'greenfields' gas pipeline developments: experience from the United States and other jurisdictions—final report, March 2002, p. 14.

ACCC understands that once established, the operational risk profile of a greenfields pipeline is unlikely to differ materially from an established pipeline. Accordingly such risks should be treated in the same manner as for established pipelines.

Consistent with the benchmarking approach outlined in the introduction to this section and with the objectives of the code and Part IIIA, costs prudently incurred that are attributable to specific risk mitigation can be included in the operations and maintenance costs of the pipeline. However, this can only apply when such costs are not otherwise compensated for as an element of the costs to which the incentive based benchmarking approach applies. For example, insurance against the event of some forms of failure (other than force majeure events) or loss of transportation tariff revenue.

Service providers also have the option of incorporating a number of other operational risk-related mitigation options. For example, economic depreciation effectively allows for the carry forward of losses in the early years of operation and the derivation of reference tariffs is based on forecast volumes, hence the pipeliner is substantially insulated from volume risks (with respect to cost recovery). Volume risks associated with demand forecasting are discussed in more detail in section 4.5. A pipeliner also has the right to unilaterally seek a review at any time of an access arrangement in the event that its circumstances materially change.[39] CPI–X incentive mechanisms also alleviate a pipeliner's inflation risk.

4.4.1 Self-insurance

In common with mature pipelines, greenfields projects face a number of specific risks that may impinge on cash flow returns available to the venture. Because such risks are non-systematic it is inappropriate to try to reflect such risks in the asset beta established for the regulatory framework. The ACCC maintains that such risks should be compensated for in the cash flow analysis.

As noted above, prudently incurred insurance costs can be included in the operations and maintenance costs (O&M) of the pipeline. Similarly, when an operator chooses to self-insure for non-systematic risk, the prudent premium may be included in the calculation of the revenue requirement.

The ACCC understands that a service provider contemplating assuming self-insurance risk would ordinarily conduct a detailed risk analysis to satisfy debt provider and/or corporate governance requirements. Such analysis is likely to include an assessment of the particular risk/s involved, the impact on the business and its cashflow should the event occur and the probability of occurrence.

Accordingly, for a regulator to adequately assess a proposal for self-insurance, in relation to prudency and validation of an appropriate premium, it would need to consider such matters as: a report from an appropriately qualified insurance consultant that verifies the calculation of risks and corresponding insurance premiums;

[39] Refer code section 2.28.

confirmation of the board resolution to self-insure; and the relevant self-insurance details that unequivocally set out the categories of risk the company has resolved to assume self-insurance for.

A regulated entity's resolution to self-insure would also be expected to explicitly acknowledge the assumed risks of self-insuring. In the event of future expenditure required as a result of an insurance event[40] such costs would not be recoverable under the regulatory framework as the relevant premiums would have already been compensated for within the operations and maintenance element of the allowed tariffs and funded by users.[41]

Therefore, where the risk is self-insurable and assumed by a service provider, one approach for compensating the service provider would be to adopt a fair actuarially determined insurance premium for each specific risk and include these as part of O&M forecast expenditures.

The following are key parameters required to model self-insured events as part of the cash-flow analysis.

- The realistic estimates of the likely occurrence of each type of event. Some probabilities will depend on the age, operating pressure of the pipeline etc. and these can be reflected as time or volume dependent probabilities.

- The expected financial impact of the event, which may be technical or related to legal liabilities. Again such costs must be realistic, for example the cost cannot credibly exceed the asset value of the company at the time of occurrence.

This is precisely the same information required to actuarially determine insurance premiums from a third party perspective but without the truncation of liabilities or risk abatement strategies available to the pipeline company.

4.5 Demand assessment

The ACCC recognises that there is inherent uncertainty in determining demand growth forecasts for a greenfields pipeline, especially where immature or undeveloped demand exists. However, the code provides a high degree of flexibility to facilitate the design of a reference tariff policy that meets the specific needs of each pipeline system.

From a regulatory perspective there are two main implications arising from uncertain demand.

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[40] An insurance event refers to an event, which triggers an insurance claim, including a notional claim in the case of self-insurance.

[41] This is also the case for expenditure arising from conventional insurance claims when users have already funded the insurance premiums.

- The difficulty associated with determining a best estimate of forecast demand.
- The increase in potential volume risks, relative to that for a pipeline with greater certainty of demand.

Demand risk faces any new investment proposal regardless of whether the assets are to be regulated or not. However, the possibility of regulation adds another dimension to such risk. Davis and Handley[42] note that should access prices be derived on the basis of applying a required rate of return to an asset base (at some date 2), conditional on an assumed level of future output which is different to that expected at the time the investment was made (date 1), then this approach is not necessarily compatible with providing appropriate signals for investment.[43] For example in the event that the regulatory assessment of expected demand occurred at a point in time after project commitment and after which some aspects of demand uncertainty had been resolved, the reference tariffs determined could vary from those anticipated on commitment.

The ACCC acknowledges this issue and the possible difficulties in managing the inherent uncertainty. As indicated in the consultation sections of this guideline, one potential solution to this problem is to bring forward the regulatory decision date so that it occurs earlier in the project appraisal and development or construction stage rather than after project success has been observed, for example, coincident with financial close of a project.

In such circumstances the regulator will then be assessing expected demand with the same information set and uncertainty considerations that are committed to by the project proponents and its financiers at financial close. Considerations for assessing forecast gas demand are discussed further below, while downside risk mitigation is addressed in section 5. Section 6 deals specifically with the issue that the regulatory framework could potentially compromise the expectations of returns (especially blue sky) thought possible at the time of project commitment.

The regulatory provisions that assist in mitigating demand risk are discussed in more detail in the following sections. Appendix 1 also provides an illustrative example of how uncertain demand scenarios can be modelled to derive an expected return. Together these incentive properties can provide greater flexibility to a prospective service provider than, for example, the approval process in the US. In the US an application for a certificate of public convenience and necessity requires that a prospective service provider applying for such a certificate must have conducted an 'open season' before submitting the application.

The open season essentially consists of 'requests for capacity' from potential new shippers as well as 'requests for relinquishment of capacity' in expiring transportation contracts from existing shippers (if the new capacity is an expansion). In this way an

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[42] Davis & Handley, loc.cit.

[43] In this context it is the expected level of demand at the time the project is committed that determines the expected return and hence the incentive to invest.

open season enables a prospective service provider to assess the demand for its proposed new or expanded pipeline network. However, the open season does not deal with the issue of transportation tariffs for new pipeline development; its principle purpose is to get an indication of shippers demand for new capacity.

4.6 Use of forecasts

The code recognises the requirement for regulators to rely on forecast data in formulating reference tariffs.[44] Such forecasts may need to be determined for:

- capital expenditure
- operations and maintenance expenditure
- demand for volumes over the life of a pipeline.

The ACCC is cognisant of forecasting difficulties and is open to consultation with greenfields pipeline proponents to discuss possible options that remain consistent with the code or Part IIIA.

It should be noted that the level of demand risk is dependent upon the extent to which foundation contracts underpin a greenfields project's viability. For example, a new pipeline supplying gas to a new or immature market faces greater uncertainty regarding future demand than a pipeline that is fully contracted and supplying a well established market. The growth in future demand for a new pipeline can often be dependent upon a number of factors, including new projects securing funding and others remaining operational (e.g. industrial plant or gas fired generation) and/or the rate at which users convert from some other fuel source to natural gas.

However, the ACCC notes that for a greenfields pipeline that is likely to pass the regulatory threshold tests, the established industry practice for the purposes of securing debt financing requires a minimum commitment of an appropriate duration from foundation type users to determine the underpinning viability of the project (for a given level of equity contribution).

The ACCC considers that the impact of demand risks on regulatory revenue can be mitigated through careful information analysis and the design of the regulatory arrangements. For example, a number of probability weighted demand scenarios could be used to determine an expected demand (E_D) forecast. An appropriate mechanism could then allow any under recoveries in the early years of an access regime to be subsequently recouped when demand grows.

Forecasts tend to be subject to an inherent element of subjectivity. Accordingly, the code provides for appropriate review mechanisms[45] to be triggered if forecasts diverge

[44] Refer code section 8.2.

[45] Refer code sections 3.18, 8.44 and 8.45.

significantly from realised outcomes. For example, if a service provider found that discounted tariffs were required to meet its volume forecasts it could seek a review of its access arrangement. Such mechanisms can be designed to ensure they will operate in a way that is understood in advance.

As a preferred alternative, demand scenarios could be linked to a benefit sharing mechanism (discussed below) so that an aberrant demand scenario is catered for in advance. The prospective owner would have adequate scope to capture some of the 'blue sky' potential of a project but some of the benefits would also flow to users. At the same time, such an approach could limit any incentive to skew demand scenario forecasts to the lower end of the spectrum. For example, the best case demand scenario might form the volume or revenue threshold point from which benefit sharing commenced. The benefit sharing mechanism could also be invoked when demand is much worse than expected. In this case users of the pipeline also bear some of the burden and the financial consequences for the pipeline developer are less severe. These options are described in greater detail in section 6.

The measures outlined above can give a service provider ex-ante certainty about how an access regime will apply and the likely returns under a range of demand outcomes. Collectively these measures can substantially mitigate the demand risks associated with regulation of a greenfields pipeline. In addition, a service provider has a number of options available to facilitate tariff smoothing/price path approaches which can be used to optimise demand growth.

The code's approach to demand risk differs from the 'defined capacity' approach adopted by the FERC in regulating gas transmission pipelines in the US. Under a defined capacity approach reference tariffs are based on the pipeline's capacity rather than forecast volumes. *Ceteris paribus*, 'defined capacity' reference tariffs are likely to be lower than if forecast demand is used, particularly in the initial stages of the life of a greenfields pipeline that has been built with excess capacity in the expectation of future demand growth. Compared with the US approach, the code provisions facilitate the transfer of some of this demand risk away from a prospective service provider to customers.

4.6.1 Forecasts, tariffs and incentives for spare capacity

In the US despite prospective service providers having the option of offering different tariff methodologies for transportation services as outlined above, prospective service providers continue to offer mostly cost-of-service based tariffs. Traditional cost-of-service based tariffs in firm transportation contracts generally follow the 'straight fixed variable' method (SFV) of tariff design. Under this method tariffs are structured to enable the prospective service provider to recover its prudently incurred costs and an adequate return on its investments.

Under the SFV method, the tariff for a firm transportation service is made up of two components, a fixed rate and a variable rate — where the fixed capacity component covers investment costs and a variable component covers the marginal costs of

transporting gas on a pipeline system.[46] The rationale behind the SFV approach is that most of the costs to obtain firm capacity are fixed, i.e. they are not a function of the amount of gas transported on the pipeline. These fixed costs are apportioned among firm shippers based on the amount of each shipper's reserved capacity on the pipeline.[47]

However, the SFV approach does not guarantee a prospective service provider will recover the fixed costs from 'overbuilt' capacity. It only allows a prospective service provider to recover all fixed costs (independent of gas throughput) for that part of the network that is fully contracted to shippers.

Consequently, if a prospective service provider has only contracted half of its capacity on a new pipeline development, the prospective service provider bears the full risk (and associated fixed costs) for the uncontracted part of the network. The SFV approach applied by the FERC does not allow the prospective service provider to recover fixed costs from uncontracted capacity from existing or new shippers. As a consequence, there are limited incentives on prospective service providers to 'overbuild' new greenfields gas pipelines in the US.[48]

In contrast to the US approach the code provides prospective service providers with a number of options that do not discourage building excess capacity in pipelines. An illustrative example of how the ACCC could assess a prospective service provider's demand forecasts to determine an appropriate reference tariff is provided at appendix 1. As noted above in relation to construction costs, the actual cost of the initial capital base is used as an input to derive a reference tariff based on forecast volumes. Importantly for service providers there is also no scope for reassessment of the regulatory asset base at subsequent regulatory reviews, subject to the provisions of section 8.9 of the code.[49] For completeness, the appendix 1 example should be reviewed in conjunction with the risk mitigation, blue sky and consultation sections of this guideline (refer sections 5 to 7 below).

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[46] National Economic Research Associates, Foundation contracts and 'greenfields' gas pipeline developments: experience from the United States and other jurisdictions—final report, March 2002, pp. 21, 36.

[47] The fixed portion of a firm shipper's pipeline rate is thus similar to the rent one pays for office or apartment space. The shipper pay a fixed fee to rent 'space' on a pipeline on a contractual basis, regardless of the degree to which the shipper actually uses the 'space' it has contracted for. The cost of reserving that space is proportional to the amount reserved, and the shipper chooses in advance how much is needed.

[48] National Economic Research Associates, op.cit., p. 22.

[49] Refer code section 8.14.

5. Additional risk mitigation considerations

This section provides guidance on the scope and flexibility a prospective service provider has under Part IIIA and the code that enable it to mitigate various categories of risk. It also outlines possible mechanisms prospective service providers might consider incorporating when formulating an access proposal. Where relevant the ACCC has enunciated its view about the scope for interpretation and application of the relevant provisions.

As discussed in section 3, the code and Part IIIA of the Trade Practices Act set out a number of principles and requirements that guide regulators and establish the bounds to their discretion. Accordingly the ACCC, as an independent statutory authority, assesses access proposals within these established regulatory frameworks. These bounds therefore provide predictability and certainty about the application of the regulatory framework.

However, within the regulatory framework a prospective service provider has a substantial amount of flexibility when formulating an access proposal. The onus remains with the prospective service provider to submit an access arrangement to the ACCC for assessment that complies with the objectives of the code[50] or an access undertaking, depending on the regulatory option sought.

5.1 Tariff structures and service contracts

5.1.1 Determination of reference tariffs

In an access arrangement, reference tariffs are derived with the objective that service providers may expect to earn a reasonable rate of return on their investment. The reference tariff serves as a benchmark price at which a prospective user is entitled to gain access to services and applies only to the reference service as defined in the access arrangement.

Reference tariffs are limited in their application to third parties seeking access and the code explicitly preserves the right of service providers and users to enter into negotiated contractual arrangements. Similarly, tariffs can be negotiated if the service required by the user is different to the reference service.

The reference tariff regime can be incentive based. For example, it may allow service providers to earn potentially higher returns than the regulatory rate of return by retaining the benefits resulting from market growth and efficiency improvements in areas such as operating and maintenance costs.

In addition the ACCC notes that reference tariffs are derived to ensure service providers can earn a reasonable rate of return on their investment. There is no restriction on a service provider and user negotiating a price above or below the

[50] Refer code section 8.1.

reference tariff, if the service required by the user is different to that provided for by the reference service.

In the US, despite prospective service providers having the option of offering different tariff methodologies for transportation services, prospective service providers continue to offer mostly cost-of-service based tariffs. Accordingly, as noted in section 4.5, the FERC continues to apply a cost based approach with an SFV as the principal methodology for regulating interstate transportation tariffs.

However, under the capacity based approach for determining tariffs the prospective service provider in the US framework is potentially exposed to greater volume risk than under the forecast volumes based approach in the Australian regulatory framework for deriving reference tariffs.

5.1.2 Contracts in existence before and after an access arrangement

The regulatory approval process for a greenfields pipeline access proposal does not affect the ability of a prospective service provider to contract on negotiated terms with users.

The code does not permit the regulator to deprive a person of pre-existing contractual rights. Nor is there any regulatory intervention into provisions that may be included in any foundation contract. The only exception is for contractual terms relating to exclusivity rights.[51] For example, under section 2.25 of the code, contracts in place before the approval of an access arrangement are preserved.

Further, under Part IIIA the ACCC is prevented from making a determination in an access dispute that would deprive any person of a protected contractual right.[52]

In the case of foundation contracts, the ACCC notes that market participants that may have significant countervailing power and familiarity with the industry may enter into these arrangements. Prudent commercial arrangements for foundation customers might ordinarily include escalation and/or discount provisions, that may be driven by factors such as realised growth in volumes, and share the risks, costs and benefits in a developing market.

5.1.3 Foundation contracts

The role of foundation type customers in Australia is similar to that observed in the US. Long-term transportation contracts in the US that involve financial commitments to reserved capacity by shippers have played a fundamental role in the development of the US gas network and continue to drive new gas pipeline development by sharing long term investment risks between service providers and shippers.[53] At the same time, the regulatory regime has evolved in tandem with

[51] Refer code section 2.25.

[52] TPA, section 44W.

[53] National Economic Research Associates, op.cit., section 2.11.2.

market conditions, to provide continued support for efficient gas pipeline development.

The arrangements for new gas pipeline development in the US have the following main characteristics:

- long-term transportation contracts between prospective service providers and shippers that underpin the size, timing and financial risks of new pipeline investments
- an 'open season' process that brings together proponents of new pipelines with prospective shippers, before application for certification by the FERC
- a transparent application and certification process under which the FERC assesses new pipeline proposals by reference to whether overall benefits outweigh costs
- the integration of the above processes with an evolving framework for FERC-decisions on whether and how pipeline tariffs should be regulated.[54]

5.1.4 Prudent discounts

It is widely accepted that price discrimination among shippers may increase economic efficiency through increased network utilisation. This will particularly be the case for pipelines that are significantly under-utilised. Consistent with this the Australian code explicitly provides for prudent discounts to be offered by shippers.[55]

The US FERC regulatory model also recognises that selective discounting can promote the efficient use of a pipeline. In the US context discounting generally refers to the cost-of-service based tariffs. The reason is that a discount on transportation tariffs encourages higher network utilisation that generally causes a pipeline's fixed costs per unit of output to decrease.

In the US prospective service providers are prohibited from granting any undue preference or advantage with respect to any transportation service, requiring that tariffs to similarly situated shippers must not be unduly discriminatory. To ensure that tariffs are not unduly discriminatory the FERC requires prospective service providers to make the discounts available to all 'similarly situated shippers', which are generally defined as shippers that take service over the same part of the pipeline and face the same end-market circumstances. Prospective service providers must file specific information to enable shippers to determine if they are similarly situated to discounted shippers[56] and publish discounts so non-discounted shippers can determine

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[54] National Economic Research Associates, op.cit., section 4.1.1.

[55] Refer code section 8.43.

[56] *Tennessee Gas Pipeline Co*., 77 FERC ¶61,877 (1996).

if they are entitled to similar discounts.[57] Prospective service providers that employ discounted rates must file those rates with the FERC.

In contrast to the economic efficiency objectives underpinning the use of prudent discounting, 'most favoured nation' (MFN) type clauses in foundation contracts are optional provisions and potentially prevent prospective service providers from offering different transportation tariffs among shippers.

NERA has observed that to the extent that prospective service providers opt to limit their flexibility to offer discounted tariffs by incorporating MFN clauses in foundation contracts, then capacity utilisation is likely to be reduced, the market will develop more slowly, and the overall efficiency of new pipeline investment is likely to be sub-optimal.[58]

In the US foundation contracts do not generally contain MFN clauses. It is not clear whether or not MFN type clauses have been widely adopted in Australia. However, it is widely understood that price discrimination on a pipeline network generally increases economic efficiency by encouraging increased network utilisation. The ACCC notes the intent of the prudent discount provisions of the code in this regard.[59]

5.1.5 Market based tariffs

Industry representatives have proposed the use of market-based tariffs for greenfields pipelines but are concerned that they may not be allowed under the Gas Code. The ACCC understands the term refers to a proposal to base the reference tariffs that would be available to third parties on the negotiated tariffs at which foundation customers contract with a service provider.

The fundamental issue to consider under this proposal is whether a pipeline should be regulated. Both the code and Part IIIA provide tests to determine whether services will be regulated. Clearly, negotiated tariffs apply in the case of an unregulated pipeline.

The FERC's January 1996 policy statement on *Alternatives to traditional cost-of-service ratemaking for natural gas pipelines*[60] only permits unregulated tariffs subject to satisfaction of tests that are required to demonstrate a lack of market power for a natural gas pipeline. In summary, the pipeline would have to either:

- demonstrate that it lacks significant market power because users have sufficient good alternatives

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[57] Order No. 566, FERC Stats. and Regs., Regulations Preambles 1991–1996 ¶30,997 (1994).

[58] ibid.

[59] Refer code section 8.43.

[60] FERC, Alternatives to traditional cost-of-service ratemaking for natural gas pipelines (Docket No. RM95-6-000), 31 January 1996.

- meet specific conditions to prevent the exercise of any market power it may have.

Regulation of gas transmission pipelines in Australia is only applied when natural monopoly characteristics exist and the service provider is capable of exerting some degree of market power.[61] To the extent that the service provider can exert market power, negotiated tariffs would be unlikely to reflect those that would apply in a competitive market. This is consistent with the Brattle Group's observation that there is no evidence that negotiated access regimes have produced any of the positive benefits, such as superior innovation of flexibility, that are sometimes cited in favour of negotiated access.[62]

When regulating pipeline services, the ACCC is required to comply with the code provisions or Part IIIA requirements which include having regard to the cost reflectiveness of access pricing proposals and providing the service provider with the opportunity to earn a reasonable return on its investment. In the case of the code, a reference tariff operates as a benchmark tariff for a specified reference service while meeting the code objectives.[63] Accordingly, in principle a negotiated tariff would only be expected to be greater than a reference tariff to the extent that the service provider can exert market power.

The ACCC is only concerned with the regulation of natural gas transmission pipelines that either meet the coverage tests under the Gas Code[64] or are subject to an access undertaking or declaration[65] under Part IIIA of the TPA.

- Under either regime, access prices are designed to provide a reasonable return to the service provider. In this regard the regulatory framework affords considerable certainty to prospective service providers.

- Where a negotiated tariff exceeds a reference tariff it would appear that the negotiated tariff would be providing the pipeline owner with a greater than normal return.

5.2 Determining the initial capital base for a greenfields pipeline

Section 8.12 of the code provides for the initial capital base (ICB) of a new pipeline to be included at the actual capital cost of the assets at the time they first enter service.[66]

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[61] In Australia the National Competition Council (NCC) assesses market power.

[62] The Brattle Group, *Third-party access to natural gas networks in the EU*, March 2001, p.2. Copies of this report are publicly available on the website of the European Federation of Energy Traders at <www.efet.org>.

[63] Refer code section 8.1.

[64] As determined by the NCC.

[65] As determined by the NCC.

[66] Refer code section 8.12.

And there is no scope for reassessment of actual cost in subsequent regulatory reviews.[67] This contrasts with the treatment of existing pipelines where the regulator must consider valuations based on methodologies such as depreciated actual cost and depreciated optimised replacement cost. Part IIIA does not provide this degree of prescription and certainty to greenfields investors. However, the ACCC is likely to value the ICB at actual cost unless there is strong reason to do otherwise.

The ACCC is aware that the costs of a greenfields pipeline may not be known with precision until some time after operations commence and that initial reference tariffs would need to be determined based on forecast capital and non-capital costs.

The ACCC considers that a forecast ICB could be used when determining the initial reference tariff in conjunction with an appropriate mechanism to adjust the tariff when the actual capital cost is known with certainty.

5.2.1 Adjustment mechanisms

The ACCC considers that section 8.12 of the code provides sufficient flexibility to allow the inclusion of a symmetric adjustment mechanism to accommodate any material variance between the forecast and final cost of the ICB.

Incorporating an appropriate adjustment mechanism would:

- alleviate any downside risk to the service provider in the event that the final cost of the ICB was greater than forecast, and
- pass through benefits to users in the event that final cost was lower than forecast.

An appropriate adjustment mechanism would be expected to: mitigate under or over recovery; avoid potential discontinuities in the reference tariff price path to avoid volatility in tariffs; and provide certainty for users.

While the design of the adjustment mechanism would largely depend on the service provider, the ACCC expects that both the timing and dollar cost effects could be parameterised and clearly expressed from the date of commencement of the access arrangement. Prospective users could then contract for capacity at the reference tariff (with ex-ante certainty as to the methodology for calculating any variance in tariffs once the actual ICB is known). As noted above, parties also retain the right to negotiate for access.

A range of appropriate adjustment mechanisms is possible. The optimal approach from the service provider's perspective is likely to depend on the weight it attaches to stability in reference tariffs as compared to the speed of cost recovery, noting that either approach would be equivalent in net present value (NPV) terms.

An illustrative approach to adjustment mechanisms is outlined at appendix 2.

[67] Refer code section 8.14. Note this is subject to the provisions of section 8.9 with respect to new facilities investment, recoverable portion, depreciation and redundant capital.

5.3 Downside risk mitigation

Section 2.28 of the code provides that the service provider may seek revisions to its access arrangement at any time. In contrast the ACCC cannot initiate an early review.[68] Similar provisions apply to an access undertaking under Part IIIA. That is, a service provider may withdraw or vary an access undertaking at any time, but only with the consent of the ACCC.[69]

These provisions afford protection to a prospective service provider in the event that unforeseen factors affect it and constrain its ability to earn a reasonable return.

Thus, service provider initiated, unscheduled revisions to an access arrangement can assist a service provider who finds unforeseen factors significantly impinging on its ability to earn a reasonable return. Further, where demand is expected to grow gradually over time, a depreciation profile may be chosen that allows the opportunity for expected early under recoveries to be recouped in later years. This is discussed in further detail in section 6.5 of this guide.

[68] Specific major events may require a service provider to submit revisions under the code. Refer Code section 3.17(ii).

[69] TPA, s. 44ZZA(7).

6. Managing uncertainty and blue sky opportunities

A criticism levelled at regulators by prospective investors is that perceptions of regulatory risk in a regulated industry act as a disincentive to investment. These perceptions are on the assumption that a regulated entity's downside risk is not capped whereas its 'blue sky' opportunities are, including the potential for regulators to claw back or otherwise limit the blue sky potential of a new investment at the next regulatory review.

These views fail to recognise the provisions of the code that mitigate both of these risks while ensuring compliance with the code's objectives of earning a reasonable return to service providers and benefit sharing with users. These are outlined further below. Prospective service providers are encouraged to discuss such options with the ACCC when formulating access arrangements for regulatory approval.

It is also instructive to note that in its paper on natural gas pipeline access regulation[70], NERA found the code to be a sound piece of regulatory legislation and demonstrated that appropriate access regulation will not deter investment in gas pipeline infrastructure. On the contrary, NERA found that sound regulatory regimes contain numerous provisions that promote rather than discourage gas pipeline investment; and appropriate regulatory regimes provide risk-averse investors with the certainty they require for their investments. In a survey of declared post tax regulatory rates of return across various jurisdictions in the United Kingdom and North America it was found that Australian regulators were providing higher vanilla post-tax weighted average costs of capital than in the other jurisdictions examined.[71] Similarly the Brattle Group noted in its comparative analysis of tariffs in the European Union that where prices were transparently linked to underlying costs they were generally substantially lower than those that were not.[72]

The code recognises that to encourage investment, a prospective service provider should be given the opportunity to reap some of the blue sky potential of the pipeline, where prospective blue sky profits are needed to offset prospective losses from a dismal (black sky) outcome. Further, the investor needs regulatory certainty on the treatment of abnormal (extreme scenarios both optimistic and pessimistic) returns during the initial forecast time horizon and certainly during the initial regulatory period/s. The inclusion of an incentive mechanism in an access arrangement[73] (or access undertaking) is an important component of a service provider's regulatory

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[70] Natural gas pipeline access regulation—Report for BHP, 31 May 2001

[56] National Economic Research Associates, International comparison of utilities' regulated post tax rates of return, March 2001.

[72] The Brattle Group, *Third-party access to natural gas networks in the EU*, March 2001, p.24. Copies of this report are publicly available on the website of the European Federation of Energy Traders at <www.efet.org>.

[73] Refer code section 8.44.

framework. The ACCC encourages service providers to develop mechanisms that will best suit their particular needs.

Without constraining the intentions of the code in this regard, the challenge for regulators is to assess access regime proposals that establish a framework which ensures the service provider's economic incentives to maximise utilisation of its assets and development of its business while not imposing unreasonable cost transfers to users.

A number of options are available to prospective service providers when formulating an access proposal that can provide certainty in the context of both blue sky and black sky scenarios. These include the term of the access arrangement/undertaking period; benefit sharing mechanisms; fixed principles, downside risk mitigation review triggers; depreciation schedules and any combinations thereof. Each of these is discussed below.

Additionally the ACCC is receptive to other proposals from prospective service providers to mitigate the risk profile of a greenfields pipeline, provided it is consistent with the objectives of the code or Part IIIA, depending on the access regime sought.

6.1 Demand forecasting

The ACCC acknowledges the inherent uncertainty a prospective service provider is likely to face in forecasting demand volumes and growth profiles, beyond its contracted foundation customer base, in immature or undeveloped markets.

The ACCC understands, irrespective of whether a greenfields pipeline is to be regulated or not, that during the investment analysis phase for a prospective greenfields pipeline the proponents conduct substantial market analysis. This detailed analysis to determine the projects likely demand and growth potential, and to secure the levels of commitment necessary from foundation customers to ensure the economic viability of the project, is understood to be an essential precursor to securing the necessary board and financing approvals.[74]

As noted above, demand forecasts will be a function of the underpinning foundation type contracts including contracted or planned expansion in foundation customer demand, and market analysis of likely demand from third party users and rate of growth in that demand. Accordingly the ACCC considers that an expected demand forecast can be modelled to account for the inherent uncertainty for the purposes of deriving a reference tariff. Demand risks could then be mitigated through the analysis of a number of probability weighted demand scenarios to provide a known revenue profile to the prospective investor for each demand scenario proposed.

[74] Macquarie Bank Limited, Issues for debt and equity providers in assessing greenfields gas pipelines, May 2002.

While there is an inherent element of judgment associated with forecasts, the code provides for appropriate review mechanisms[75] in the event that forecasts diverge significantly from realised outcomes. For example, mechanisms are available to ensure that under recoveries in the early years of an access regime can be compensated for in the regulatory framework.

The ACCC notes that the use of such a framework may increase the incentive for prospective service providers to 'game' its expected demand forecasts. For example, a prospective service provider could have the incentive to skew, or weight, forecast demand probabilities in favour of less optimistic outcomes (while still maintaining an NPV not less than zero), thus leading to a lower expected demand and a higher reference tariff.

However, if this approach was adopted, it could potentially result in an adverse outcome for the service provider such as negative implications for longer term market development (regarding price signalling) and the lowering of a benefit sharing threshold point (see 6.2 below). The formal approval process of an access proposal also requires public consultation that would provide an opportunity for interested parties to comment on the proposed demand forecasts.

Accordingly, an effective framework needs to establish an agreed basis that provides certainty at the outset and incentives for a prospective service provider to maximise the use of its reference service and earn a greater than normal return up to a pre-determined point and for a known period. The ACCC considers that the inclusion in an access proposal of a threshold point from which benefit sharing should occur, is an appropriate mechanism.[76]

6.2 Benefit sharing mechanisms

There is a range of benefit sharing mechanisms that a prospective service provider could consider when formulating an access proposal. A benefit sharing mechanism would involve the inclusion of a methodology for the sharing of greater than expected revenues between the service provider and users, and may also identify an event that will invoke the benefit sharing provisions. The inclusion of such a clause in the access arrangement or undertaking would provide the service provider with certainty from the outset, regarding the nature and effect of any benefit sharing and at what point it will commence. Possible mechanisms could be based on:

- demand focused capacity/volume thresholds
- revenue based
- profit based, or

[75] Refer code section 3.18.

[76] In the case of an access arrangement the threshold would need to be formulated in accordance with review mechanisms set out in section 3.18 of the code.

- a combination of the above.

Expected demand, revenue and profit scenarios can be linked to any benefit sharing mechanisms that may be required. This would ensure the appropriate incentive to capture some of the blue sky potential of a project and alleviate the potential incentive to skew demand scenario forecasts to the lower end of the spectrum.

It should be noted that the inclusion of a benefit sharing mechanism does not involve or represent a review of the access proposal before the expiration of the agreed regulatory period, in any way. Rather, benefit sharing would only commence once a threshold point has been reached and would follow the methodology previously agreed upon and set out in the approved access proposal.

The ACCC also notes that the benefit sharing mechanism would only come into operation after the prospective service provider has been adequately rewarded for undertaking the investment, and the service provider would still continue to receive a financial benefit from any further growth in demand.

An illustrative example of one possible form of a potential benefit sharing mechanism to apply once the threshold has been reached is provided at appendix 3. This example is based on a demand focused volume threshold. Note that in this example any further increase in demand beyond the threshold continues to be revenue and profit cumulative to the service provider, albeit at a reduced rate. The benefit sharing mechanism would only be initiated once a pre-determined volume threshold had been reached. As outlined above the ACCC envisages that such a threshold would be set such that the prospective service provider would realise and retain the blue sky benefits it identified as potentially realisable in deriving its expected demand, before the benefit sharing provisions took effect.

It should also be noted that the sharing mechanism proposed at appendix 3 is symmetric in that the costs to the pipeline developer of abnormally low demand is diminished with potential users of the pipeline sharing those costs in higher future tariffs.

6.3 Preservation of blue sky profits

A major concern of the pipeline industry seems to be that the regulatory framework will operate in a non symmetric fashion so that at the first review of an access arrangement the regulator will observe the current demand levels then revise reference tariffs on the basis of these more certain demand forecasts. When these new forecasts are higher than the average of the forecasts proposed initially this implies a reduction in tariffs relative to what would have been reasonably expected at the time of commitment to the pipeline proposal. The asymmetry emerges from the fact that if demand turns out to be worse than expected then raising tariffs to restore the required return may not be possible with weak levels of demand.

This is illustrated in figure 6.1 below. The revenues shown in this figure are based on the revenue sharing example in appendix 3. The three upward sloping revenue lines are the revenues expected under the three scenarios from tariffs set at the commitment stage of the pipeline project. Of course each of these revenue streams gives rise to a

different achieved return to capital as was expected ex ante. These ex ante returns are recorded in the first column of table 6.1.

However, if the first regulatory review for the period commencing period 6 was based on demand observed at that time, then the tariffs necessary to maintain the required rate of return into the future would be different to those based on the average of the three potential scenarios considered possible at the time of project commitment.

It is clear that both scenarios two and three could sustain the required WACC looking forward from period 6 with a lower tariff than previously determined. If this was the basis for setting tariffs for period 6 onwards the revenue stream expected in scenarios two and three would be that given by the dark horizontal line shown in figure 6.1, capping revenues at $75 million.

Of course, if this was the expected regulatory treatment, using the ex post observation of actual demand, then the expected returns would be less than those at the outset without a regulatory reset and there would be an inadequate return to justify investment. The lower returns are shown as column two in table 6.1. The average over the three scenarios is 7.6 per cent, below the required WACC of 8 per cent.

The purpose of this section is to confirm that this is **not** the proposed regulatory framework that the ACCC would apply to greenfields investments. Instead, subject to the length of the initial regulatory period and the relevant forecast interval, a regulatory reset based need not be based on observed demand at a periodic review. In such reviews the forecast probabilistic scenarios would be maintained for the timeframe over which they were made. Beyond that point it would be expected that market demand would have stabilised at a level which would make the application of the standard approach to regulation for mature pipelines more appropriate. At this point in time the transition would not compromise returns as it would be taken into account when assessing prospective ex ante returns under each scenario.

An obvious concern is whether this approach is invalidated when demand forecast scenarios are proven to be incorrect. This may be a result of dramatically higher or lower outcomes. The answer to this question must be no. That is why the introduction of the benefit sharing mechanism is important. It does not correct for an invalid set of forecast scenarios but it does moderate the impact towards the regulatory outcome that would have emerged had a better set of forecasts been made.

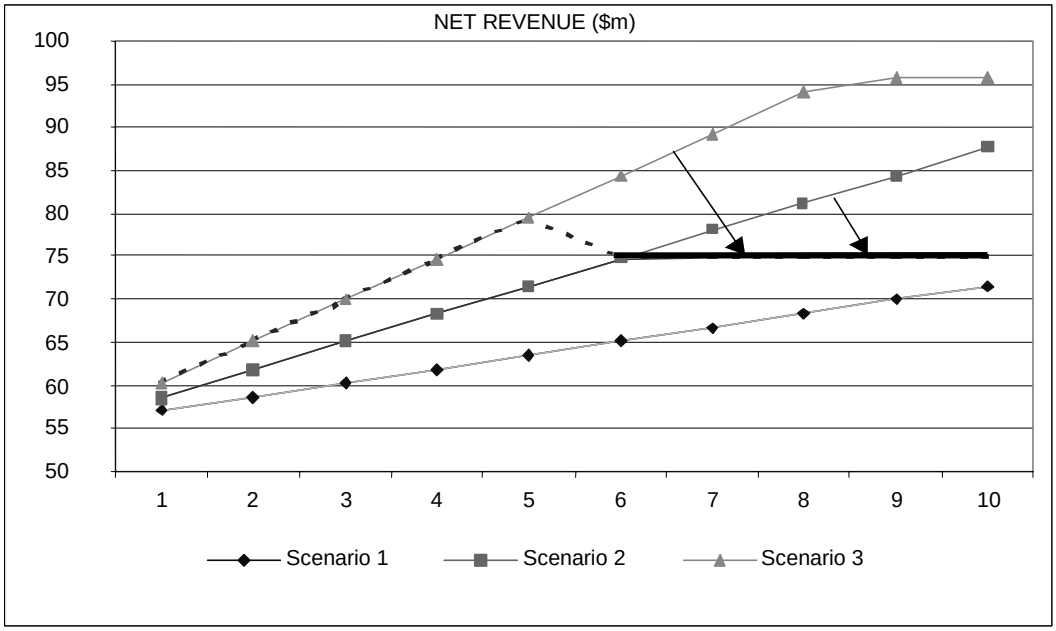
The impact of revenue sharing is shown in the third column in table 6.1. The returns achievable in the upper (scenario 3) and lower (scenario 1) demand scenarios are modified slightly, but the expected return on capital is not compromised and remains at 8.0 per cent. Appendix 3 gives further examples of what happens with revenue sharing when outcomes are much higher/lower than forecast.

The key reason why the forecasts cannot be revisited even when proven incorrect is that it is impossible to come up with a completely accurate set of ex ante forecasts at project commitment. Although the robustness of the ex ante forecasts is likely to be related to the proportion of foundation customers, their veracity can only be assessed once actual demand levels have been observed.

Under the Gas Code the regulator cannot initiate a review of an access arrangement when circumstances are observed to change except at a review.[77] The important point here is that the regulator will not take account of updated demand forecasts even at the time of a scheduled review occurring in the forecast time horizon.

In contrast to the options available to the regulator, the service provider may seek a review on the basis of changed circumstances. However, an important corollary of the approach outlined here is that a shortfall in demand expectations cannot be used as the basis for raising reference tariffs. Instead, the revenue sharing mechanism also provides the downside protection likely to be sought by the service provider. As noted in appendix 3, the protection is unlikely to come in the form of higher immediate tariffs (which would have the effect of reducing demand further) rather capitalisation of financial losses is the preferred mechanism. This enables a more satisfactory return to be achieved even in a black sky scenario but over a longer timeframe. Of course, not all financial loss can be compensated for in a sharing mechanism. The amount will depend on the level of sharing established as part of the sharing mechanism. A higher level of sharing provides greater protection but also shares more of the blue sky profits with customers.

Figure 6.1 Revenue expected from three different demand scenarios proposed with and without reassessment of demand expectations at first review for the period commencing in period 6.



[77] Specific major events may require a service provider to submit revisions under the code. Refer Code section 3.17(ii).

Table 6.1 Estimates of achievable return (WACC) on capital in different scenarios (%)

Scenario	Ex Ante	Ex Post	Sharing
Low (scen 1)	7.0	7.0	7.2
Middle (scen 2)	8.0	7.7	8.0
High (scen 3)	9.0	8.0	8.8
Average	**8.0**	**7.6**	**8.0**

6.4 Duration of an access arrangement

The code allows the regulator to consider an access arrangement period of any length. However, when the access arrangement period is greater than five years the code requires the regulator to consider whether mechanisms should be included in case the risk of forecasts on which the terms of an access arrangements were based and approved were incorrect.[78]

The ACCC's final decision for the Central West Pipeline (CWP)[79] provided for an access arrangement period of approximately 10 years. The extended period was to provide the service provider with an additional incentive to develop the natural gas market in the central west and (potentially) central ranges.

By allowing for a longer access arrangement period, and in conjunction with any benefit sharing mechanism as outlined above, the service provider is able to retain for a longer period any higher returns it earns from outperforming its forecasts. In effect, the business has the potential to earn, and retain for an extended period, a rate of return higher than the benchmark set by the ACCC. The ACCC considers that a longer period provides a greater incentive to the service provider to improve its performance and build its markets and the opportunity to reap more of the project's blue sky potential. Under the code, in the event that expected returns are not realised service providers are also able to seek a review at any time.[80]

With regard to Part IIIA, while an access undertaking must specify an expiry date, no maximum or minimum term is specified.[81] Therefore, as with the code, the term of an access undertaking is flexible.

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[78] Refer code section 3.18.

[79] ACCC, Access arrangement by AGL Pipelines (NSW) Pty Ltd for the Central West Pipeline final decision, 30 June 2000.

[80] Code section 2.28.

[81] TPA, s. 44ZZA.

6.5 Fixed principles

The service provider can also seek to ensure certainty for the application of structural elements of the access arrangement by incorporating fixed principles in its reference tariff policy.[82] Fixed principles may include any structural element. A fixed principle may not be changed without the agreement of the service provider for a specified period, the fixed period. However, in determining the fixed period regard must be given to the interests of the service provider, users and prospective users.

Sections 8.47 and 8.48 of the code deal with fixed principles. They provide a means of establishing certain aspects (structural elements) of regulatory certainty across access arrangement periods. In this way a pipeline company seeking certain provisions to be sustained over a long term can do so without necessarily having to propose a very long access arrangement duration. Structural elements specifically include:

- the depreciation schedule
- the financing structure
- that part of the rate of return that exceeds the return that could be earned on an asset that does not bear any market risk.

These provisions can give investors long-term regulatory certainty over how their investment will be treated. The provisions clarify parameters over which the regulator might otherwise seek to exercise discretion and which could leave investors unclear about future regulatory changes.

6.6 Depreciation

Under the code a depreciation schedule should reflect the following principles[83]:

- the change in reference tariffs over time is consistent with the efficient growth of the market for the services provided
- depreciation occurs over the economic life of the asset(s) with progressive adjustments where appropriate to reflect changes in expected economic lives
- an asset is depreciated only once and that total accumulated depreciation will not exceed the valuation of the asset when initially incorporated in the capital base.

Standard straight-line depreciation over the economic life of the asset has typically been the methodology used when depreciating a pipeline's capital base. However, provided that the principles of the code are adhered to, a service provider is able to use an alternative approach.

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[82] Refer code section 8.47.

[83] Refer code section 8.33.

For example, the ACCC's CWP final decision provided for the use of economic depreciation as part of the service provider's NPV/price path methodology to determine total revenue. Economic depreciation was calculated in the following manner:

Economic depreciation = total revenue – operating costs – return on capital

The ACCC approved, with qualifications[84], the service provider's proposed economic depreciation approach in recognition of the beneficial effect it would have in allowing the service provider to recoup under-recoveries accrued in the early period of the life of the CWP. This approach also provided lower tariffs during the initial phase of the life of the CWP, enabling greater opportunities for market development. This approach to depreciation was considered consistent with the code objective that the service provider should have 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.[85] This approach is particularly helpful for new pipeline developments where full cost recovery would imply high initial tariffs and consequently poor take-up of available capacity. The approach means that the company can charge lower tariffs initially and encourage gas usage without incurring a non-recoverable financial loss.

Part IIIA does not specify any particular depreciation methodologies. Consequently a prospective service provider has equal flexibility in tailoring an appropriate depreciation methodology to meet its requirements.

6.7 Post-tax revenue handbook

The ACCC released the *Post-tax revenue handbook* and related model (PTRM)[86] in October 2001. The handbook presents a simplified model that provides interested parties with an overview of the post-tax revenue model as applied by the ACCC in its regulation of various Australian utilities.

Prospective service providers can apply the concepts outlined in this document and examples to determine the necessary inputs for the PTRM and thus derive indicative unadjusted and smoothed reference tariffs. Subject to the robustness of input data, the outputs derived in this manner will be indicative of the ACCC's approach to assessing a prospective service provider's access proposal.

The PTRM also includes a normalisation module and an example of the normalisation approach that can be adopted to avoid revenue or price volatility in the face of rapid

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[84] ACCC, Access arrangement by AGL Pipelines (NSW) Pty Ltd for the Central West Pipeline final decision, 30 June 2000, pp. 68 – 72.

[85] Refer code section 8.1(a).

[86] Electronic copies of the handbook and model can be found on the ACCC's website under <www.accc.gov.au/gas>

changes in a service provider's tax liabilities by adjusting depreciation to offset tax costs in an NPV neutral manner.

7. Consultation and provision of information

The ACCC notes that there are significant similarities between the processes that it must follow when assessing access arrangements and access undertakings. Both require it to undertake a public consultation process and, as noted earlier, the ACCC will consider similar frameworks in assessing any application.

7.1 Consultation before submitting an undertaking or access arrangement

As discussed throughout this guideline, a prospective service provider has a number of options available when formulating an access arrangement or undertaking that best addresses the requirements and risks of its particular pipeline project. The ACCC welcomes open and constructive discussions with prospective service providers to facilitate the development of an appropriate regulatory approach that recognises the particular circumstances of a proposed greenfields pipeline project. The ACCC has developed this guideline to provide users with certainty of regulatory outcomes.

To provide a preliminary non-binding view on reference tariffs to a prospective service provider, the ACCC will require sufficient information to complete its assessment. While the prospective service provider would not be bound to provide the information discussed in the next section, the ACCC would consider this a good indication of the information necessary to provide a considered and informed assessment of likely reference tariffs. Notwithstanding issues raised during public consultation, the accuracy of the ACCC's preliminary views are very much dependent upon the amount and relevance of the information provided.

The ACCC would consider the process of providing a preliminary view as confidential in nature and any information provided by the prospective service provider, including the outcome of the assessment, would be treated as **commercial in confidence**.

In the event that a formal application is made the ACCC is then bound by the consultation provisions of the code or Part IIIA, depending on the nature of the regulatory regime sought, and service providers are required to provide all relevant information.

Where possible the ACCC aims to preserve the confidentiality of commercially sensitive information during the formal consideration of an access regime proposal. Prospective service providers are referred to sections 7.11 to 7.14 of the code and page 70 of the *Access undertakings* guideline for the position on preserving confidential information for access arrangements and undertakings respectively.

7.2 Provision of information

Under the code, a service provider is normally required to submit access arrangement information in conjunction with its proposed access arrangement. Section 2.7 of the code states that the access arrangement information may include any relevant information but must include at least the categories of information described in attachment A to the code (a summary of which is shown in Box 7.1).

The access arrangement information must contain sufficient information to enable users and prospective users to understand the derivation of the elements in the proposed access arrangement and to form an opinion as to the compliance of the access arrangement with the provisions of the code.[87]

Box 7.1. 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 on equity and debt; and debt/equity ratio assumed.
Category 3: operations and maintenance costs
Fixed versus variable costs; cost of services by others; cost allocations, for example, between pricing zones, and cost categories.
Category 4: overheads and marketing costs
Costs at corporate level; allocation of costs between regulated and unregulated segments; cost allocations between pricing zones, services or categories of asset.
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.

In the case of an access undertaking, Part IIIA does not prescribe the information that should be provided in an access undertaking. However, the ACCC's *Access undertakings* guideline does provide a broad list of information that could be included in any proposal for any access undertaking.[88] As discussed earlier, the two regimes are very similar and it is likely that the same type of information would be necessary to assess the application under either access regime. Therefore, prospective service providers submitting an access undertaking should also be guided by the information set out in attachment A of the code.

As noted in section 5.2, actual capital costs will be used to value the initial capital base for a greenfields pipeline once it is completed. However, in the case of a pipeline yet to be constructed or still under construction, the actual capital costs of the pipeline are not yet known. In the case of future capital expenditure and operating and maintenance costs, both new and established pipelines are required to provide forecast values. While these costs may not be as easily ascertained for a new or proposed pipeline, it is highly likely that they will fall within a fairly limited range.[89]

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[87] Refer code section 2.6.

[88] See ACCC, Access undertakings—a guide to Part IIIA of the Trade Practices Act, September 1999, p. 65.

[89] Refer appendix 2.

7.3 Public consultation and assessment procedures

The public consultation and assessment procedures are essentially the same for both an access undertaking and an access arrangement. A service provider submitting an undertaking can vary or withdraw it at any time subject to the ACCC's consent. However, under the code, only a service provider who has submitted a voluntary access arrangement[90] (that is, a pipeline that has not been deemed covered) can withdraw its access arrangement before approval. Although service providers subject to an access arrangement under the code may submit to the regulator proposed revisions at any time.[91]

Further, while the ACCC is required to issue a draft decision under the code, the ACCC can exercise its discretion to issue a draft report for an undertaking depending upon whether any difficult or controversial issues have been raised. Box 7.2 outlines and compares the public consultation and assessment procedures for both an access undertaking and an access arrangement.

7.4 Timeliness of regulatory rulings

The assessment of access regime proposals, provision of all relevant information by a service provider and required public consultation processes outlined above necessitates an assessment period of several months. The code[92] provides that the regulator must issue a final decision within six months of receiving a proposed access arrangement.

Six months is considered to be a reasonable length of time, given the long lead times inherent in gas pipeline investments and time needed for consultation and due process. The ACCC notes that any delays in issuing an access arrangement final decision is likely to be a concern for providers of capital. To mitigate timing uncertainties for regulatory decisions regarding greenfields pipeline projects it is incumbent on project proponents to pro-actively manage regulatory determination processes to ensure the regulator is able to promulgate determinations within the minimum prescribed timeframe.

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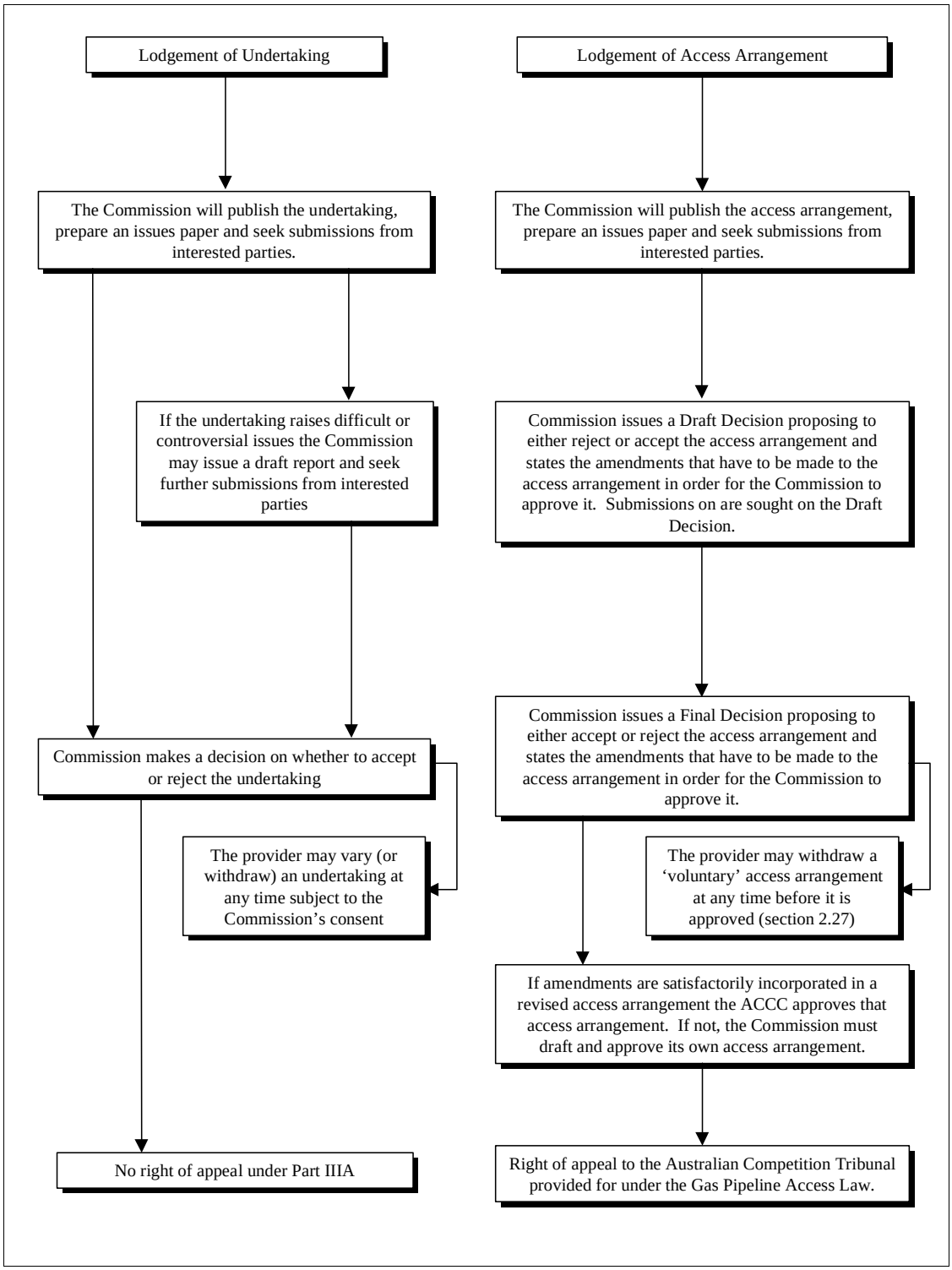
[90] Refer code section 2.3.

[91] Refer code section 2.28.

[92] Refer code section 2.21 (subject to 2.22).

Box 7.2: Comparison of public consultation and assessment procedures



Appendix 1

Example for derivation of revenues when expected demand is uncertain

The following example sets out one possible approach to setting parameters of customer demand survey results and determining expected returns where there is uncertainty. The ACCC notes that there may be many ways of developing such a framework. However the following example is provided.

In a greenfields project part of the demand is underwritten by foundation contracts but a part of expected demand is uncertain and may not emerge as envisaged despite market research. This example quantifies aspects of uncertainty inherent in forecasting demand and growth factors beyond the certainty provided by foundation contract type commitments. Assessment of the information set outlined in this example is consistent with the due diligence type requirements of debt and equity providers in their respective analyses of a pipeline proposal.

Interesting points to note in the following example are:

- the manner in which a large number of simulations for a number of customer classes with varying take up rates can be modelled; and

- how capacity constraints impact on the blue sky earnings capability of a given pipeline specification, thus enabling project proponents to assess the optimal sizing and amount of spare capacity to build into a pipeline from the outset.

The basic question of future demand is just as critical for investment decisions concerning whether to build the pipeline and its optimal diameter/sizing as it is for any regulatory decisions concerning tariffs. The nature of information required is the same for both tasks. Both require an appreciation of who the potential customers may be and what their energy demands are likely to be. For existing users of energy in the region served this requires an assessment of the delivered gas price that would lead them to switch to natural gas as a primary source of energy, the capital costs involved in doing so and how long this may delay any such switchover. In addition there will be other potential customers who may emerge because of the availability of gas supply. The delivered gas price will be important in determining what new businesses may be attracted.

To be better informed on these issues it should be possible to survey customers about their likely needs. It is not expected that such a survey will eliminate uncertainty. It is likely that considerable uncertainty would remain about the intentions of many potential customers. However, such a survey would allow a probabilistic appreciation of the potential market.

For each customer it is expected that the pipeline proposers could develop an opinion concerning the following:

- the existing energy needs of a customer and whether these are likely to expand

- the delivered price of gas at which the customer is likely to find gas a more economical energy source in the long term
- short term factors such as new capital costs that may prevent or delay early adaptation
- the impact that the delivered gas price is likely to have on a customer's choice of energy and timing of any changeover decision
- other factors influencing a customer's decision to become a gas user.

There will be concerns regarding some responses and overall considerable scope for subjective interpretation of any information provided by potential customers. Nevertheless, any serious attempt to compile such information will help define the nature and extent of uncertainty concerning possible demand. The mere act of identifying potential customers is a major advance even before questions concerning their costs and needs are explored.

There are many ways of developing such a framework. Below, just one possible approach to setting parameters of customer demand survey results is considered.

Customer specific demand forecasts

A customer's existing demand for energy is estimated to be E(0) and this demand is expected to increase by x per cent of GDP growth g (or a similar index of economic activity). On the basis of the existing energy source (which may be LPG, electricity, diesel etc.) it could be estimated that the price of delivered gas that would make a switch to gas as the energy source economically attractive in the short term is A(0), in the absence of other switching costs.

This switching price may be expected to vary as time progresses according to A(t). This may link to the rate of change in alternative fuel sources (say a(t) per annum). However, an immediate switch may be ruled out because of changeover costs and existing operational plant which is too costly to replace immediately. The effect of such changeover costs is to reduce the threshold price at which gas becomes economically attractive. This impact could be assessed as K(0) which is the amount the gas price P(0) would need to be below A(0) to achieve an immediate conversion. This discount can be expected to reduce over time as existing plant is written off and needs replacement, say in L years time. A simple linear expression for variation of the conversion discount over time could be used to approximate this aspect of the decision:

$$K(t) = K(0) \cdot t / L \qquad (1)$$

To determine what transport tariff is needed to attract the customer the well head gas price G(t) needs to be subtracted.

Setting these parameters identifies the period (t) in which the customer changes over to gas according to whether the following relation is true:

$$P(t) < A(t) - K(t) = A(t) - K(0) \cdot t / L \qquad (2)$$

The price of alternative fuels A(t) is determined by the process

$$A(t) = A(t-1) \cdot (1 + a(t)) \qquad (3)$$

where a(t) is the growth in alternative fuel prices from the previous year.

The quantity of gas is likely to be fairly insensitive to the transport tariff and would be equal to

$$E(t) = E(t-1) \cdot (1 + x \cdot g(t)) \qquad (4)$$

The service provider has some discretion when conversion may take place by setting the tariff

$$T(t) < P(t) - G(t)$$

$$< A(0) - K(0) \cdot t/L \qquad (5)$$

In any event if this inequality holds it assumes that the potential customer switches to gas in period t and contracts for E(t) units and continues to use gas as its main fuel source thereafter.

This form of analysis can be considered for a range of customer types and the survey results expanded to develop a picture of the overall market.

Setting such parameters suggests what may be the appropriate sizing of the pipeline, the optimal discount to offer foundation customers and an efficient time profile for change in tariffs.

This is a rather simple characterisation of customer behaviour but there is no reason why it can not be made as sophisticated as desired by the pipeline sponsor.

Setting the parameters does not require a high degree of precision and certainty. First of all it is unlikely that the survey will be exhaustive and will therefore require some extrapolation to the market as a whole. Secondly, customers being surveyed may be indefinite about their requirements and the surveyor may need to qualify the results with subjective estimates based on experience and secondary information sources. Thirdly a service provider may constrain itself by charging the same tariff to all customers.

The degree of uncertainty associated with each parameter then becomes an integral part of each assessment. For simplicity we assume below that such uncertainty is expressed as a normal distribution with the standard deviation chosen to reflect the degree of uncertainty.[93] To scale the survey up to derive overall market behaviour it is necessary to survey each customer class and estimate the number of customers and likely volumes associated with each class. The estimated numbers in each class is also subject to uncertainty but for larger customers it is expected that the survey

[93] actually any probability distribution may be contemplated.

would involve total coverage and that the element of uncertainty is limited to whether a potential major user may choose to establish a new plant or not.

Table A1.1. Summary of parameter definitions for a company being surveyed

Parameter	Definition
E(t)	Energy demand in period t
x	Ratio of demand to GDP growth
A(t)	Price of alternative energy
a(t)	Increase in A(t) over previous year
K(t)	Measure of gas changeover cost
L	No years for K(t) to fall to zero

In addition to specific customer requirement forecasts a number of market wide forecasts are required.

Market-wide forecasts

Although generally available market growth forecasts could be used, by themselves they do not capture uncertainty associated with them. The following is an example of one approach that could be adopted.

Benchmark economic growth g could be based on official forecasts of real GDP growth but uncertainty could realistically be represented as a near random walk (autoregressive) process about the level chosen. For this example

$$g(t) = 0.03 + u(t) \quad \text{where} \quad u(t) = 0.6u(t-1) + e(t) \qquad (6)$$

and e(t) is distributed as N(0, 0.01). i.e. normally distributed with mean zero and standard deviation 0.01.

The price rise for alternative fuels a(t) is assumed to follow a similar process. In this case it is assumed all alternative fuels follow the same price growth but a number of different fuels could have easily been considered. In this example assume

$$a(t) = 0.02 + v(t) \quad \text{where} \quad v(t) = 0.4v(t-1) + e(t) \qquad (7)$$

and e(t) is distributed as N(0, 0.01).

Another global variable is the well head gas price G(t). In this example it is assumed it follows the same price path as the alternative fuels

$$\text{That is} \quad G(t) = G(t-1) \,.\, a(t) \qquad (8)$$

For the purpose of this example gas distribution costs are not explicitly modelled and therefore could be thought of as being included with the well-head price of gas G(t).

Generating the demand scenarios

An example of survey outcomes for 10 customer classes is illustrated below.

Table A1.2. Customer characterisation survey example.

Customer class	Expected number of customers (random)[1]	E(0) Energy demand at time 0 (PJ pa)	X Ratio of demand to GDP growth	A(0) Price of alternative energy at time 0	Initial gas change-over cost K(0) (random)[2]	Remaining life of existing plant L (random)[2]
1	2	10	1.00	10	N(1,0.3)	N(5,2)
2	3	4	0.80	10	N(2,1)	N(5,2)
3	6	2	1.20	10	N(2,1)	N(5,2)
4	11	1	1.00	10	N(2,1)	N(5,2)
5	23	0.5	0.50	10	N(2,1)	N(5,2)
6	45	0.2	1.50	10	N(2,1)	N(5,2)
7	75	0.1	1.00	10	N(2,1)	N(5,2)
8	165	0.05	1.00	10	N(2,1)	N(5,2)
9	550	0.02	1.00	10	N(2,1)	N(5,2)
10	2250	0.005	1.00	10	N(2,1)	N(5,2)

Notes: 1. Expected number of customers is generated from a number distribution with a mean as specified and a standard deviation set equal to 20 per cent of the mean. The sample values are rounded to the nearest whole number.

2. Random value from normal distribution identified in the table cell. For example N(5,2) denotes selection of a random number from a distribution with a mean of 5 and a standard deviation of 2.

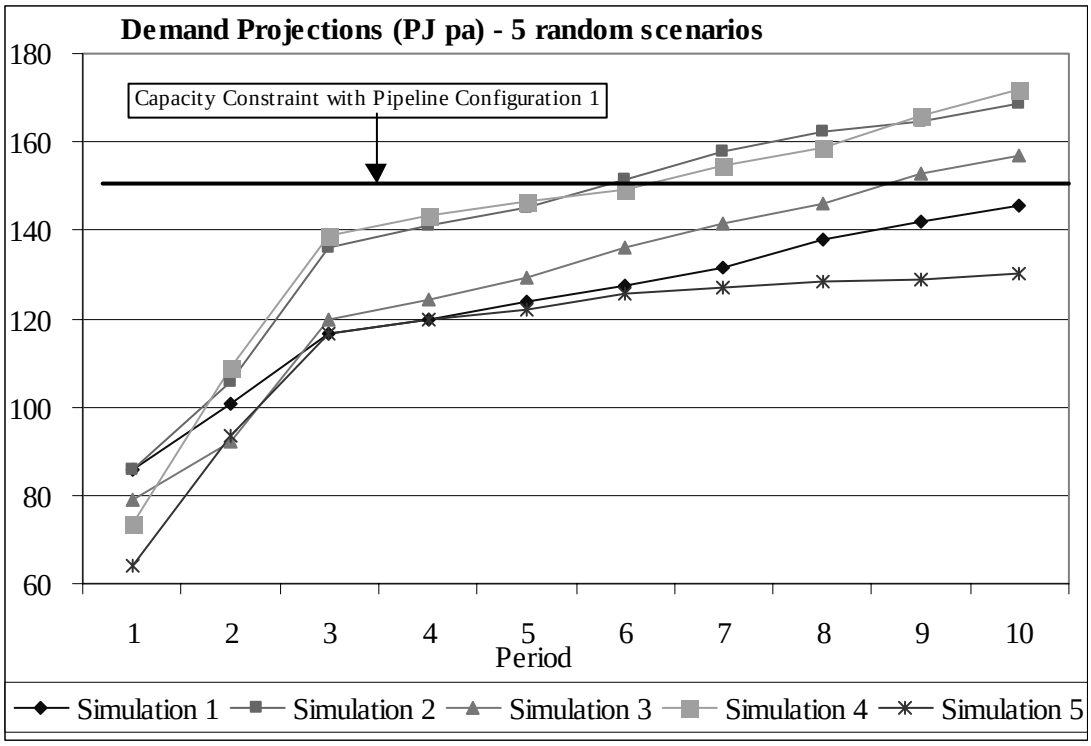
To generate demand forecasts based on these parameters the tariff path needs to be specified. In the sample simulations shown below it is assumed that the tariff in year 0 is $1.100 per GJ and escalates on a yearly basis according to a CPI-X rule (CPI=2.5% and X=1%).

The first five scenarios generated by the parameter assumptions are shown in graph A1.1.

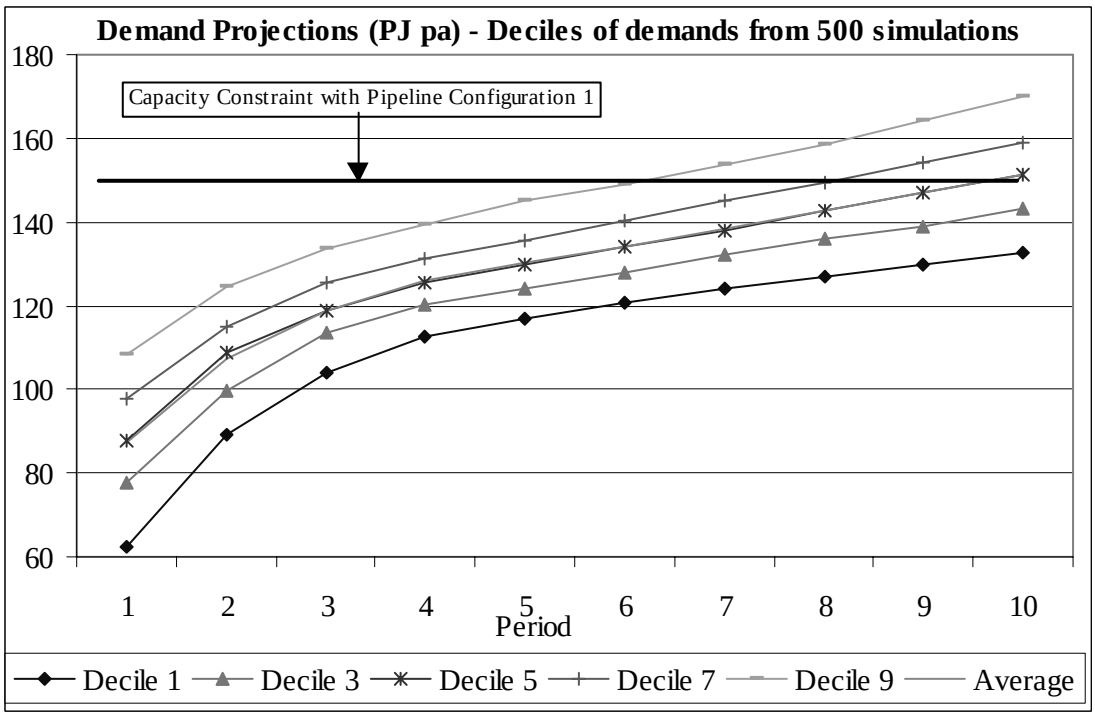
Note that in all five scenarios demand in period one is non zero, that is **some** customers will require gas in the first period of each simulation. However, this is not necessarily the case for individual customers whose changeover costs make an immediate transition to gas uneconomic. The non zero results in the early years indicates that there are always some customer classes for which an immediate transition to gas is worthwhile. The relatively steep take-up in the early years reflects the fairly rapid reduction in the transition related disadvantages of gas. That is the more rapid demand growth in early years is caused by customers switching to gas from other fuel sources as changeover costs diminish. In later years, when most potential customers have made the switch growth relies purely on the growth in energy demand of existing customers.

To obtain a fuller appreciation of the spectrum of scenario possibilities significantly more simulations are required. Below the analysis is based on 500 scenario simulations. The range of outcomes is illustrated in graph A2.2 which shows demand levels in each year based on a decile based breakdown of volumes in each year. The values for the 1st, 3rd, 5th, 7th and 9th deciles are chosen as an indicator of the median within each quintile range.

Graph A1.1. Demand projection scenarios based on randomised parameter



Graph A1.2. Selected deciles of demand in each year from 500 projection scenarios based on randomised parameter values



It should be noted that graph A1.2 also plots the average demand scenario over the 500 simulations and that this almost coincides with the plot for the 5th decile of demands simulated (i.e. the median outcome). This suggests that the demands are more or less symmetrically spread either side of the average or expected demand scenario.

The five scenarios graphed represent a summary of demand outcomes and could be used as a basis for further simulations without the need to simulate demand from individual customers. In this summary portfolio of outcomes each scenario presented has equal probability (0.2). Such a simplified approach would be attractive when the complexities of calculating costs and rates of return in conjunction with each demand simulation represents a significant computational burden.

Revenue and rate of return implications

Any developer of a pipeline needs to go one step further before deciding on the feasibility of the project. The cost of building and operating the pipeline needs to be factored into the analysis to observe whether a satisfactory return is available from the project. To illustrate this aspect of the analysis it is assumed that two pipeline configurations are possible each with expansion capacity provided by up to two compressors (see table A1.2).

Table A1.3. Possible pipeline configurations—capacity and costings

Aspect	Configuration 1	Configuration 2
Pipeline cost	$500m	$600m
Economic life (years)	80	80
Initial capacity (PJ pa)	100	150
Capacity (1 compressor)	130	195
Capacity (2 compressors)	150	225
Cost of compressor	$30m	$33m
Economic life (years)	30	30
Real operating costs pa	$10m	$12m

The returns available from demand generated in any scenario can be linked with a return on equity available with either pipeline configuration. A summary of returns observed from the 500 scenarios is shown in table A1.4. The simulations assume that compressors are installed just in time to meet any projected demand in the year ahead. However, if maximum capacity is exceeded no additional revenue is forthcoming as the additional demand cannot be met. This acts as a cap on the blue sky available from higher demand scenarios, particularly in the case of the smaller pipeline proposal.

Table A1.4. Summary of rate of return outcomes from each pipeline configuration (return on equity over 10 years per cent pa)

Demand scenario	Configuration 1	Configuration 2
Average of 500 scenarios	13.81	14.74
Average demand scenario	14.02	14.91
Decile 1 scenario	10.93	11.33
Decile 3 scenario	12.73	13.23
Decile 5 scenario	14.03	14.94
Decile 7 scenario	15.25	16.30
Decile 9 scenario	16.62	18.05
Average of 5 scenarios	13.91	14.77

The average demand scenario is not significantly affected by the capacity constraint and therefore does not capture the negative impact on return from the constraint. In other words the returns from the various scenarios under pipeline configuration 1 reveal that it is not sufficient to merely consider the average demand scenario. Taking the average of the returns estimated for each of the 500 demand simulations offers a better guide to the expected return. In configuration 1 the return from the average scenario is quite a bit higher than the expected return overall even though the demand scenarios are symmetrical about the mean. This is a result of the average demand scenarios not being constrained by pipeline capacity. However, it is clear that in a number of scenarios (see graph 1.2) the capacity will be a constraint on blue sky revenues within the 10 year period being considered in about 20 per cent of the outcomes with pipeline configuration 1.

This conclusion is evident in the returns calculated for configuration 2 when capacity constraints are not a limit on additional business (indeed the second compressor is required in only about 0.25 per cent of the simulations). The average of returns obtained in individual simulations is close to the return expected from the average scenario. Further, the higher returns from the demand corresponding to the 7th and 9th deciles are much higher for configuration 2 and this lends support to the conclusion that the capacity constraint reduces the return expectations with pipeline configuration 1.

It was noted above that the return analysis could be performed using the summary five decile scenarios graphed above. Because these include scenarios where the capacity constraint bites, the asymmetry effect is reflected in the average of returns from the five scenarios. Each of the five scenarios represents the median of a range of outcomes with equal probability. Therefore the unweighted average of returns provides an unbiased estimate of the expected value of returns over all outcomes. This average is close to the result obtained with 500 simulations and illustrates the computational saving of working with the summary scenarios.

Summary

Significantly, the expected return from configuration 1 is much lower than for configuration 2, suggesting that it will be more cost effective to build the larger pipeline despite the higher costs and the fact that in configuration 2 the pipeline is not expected to be used to its full capacity in many instances.

The example of capacity constraint illustrates the value of scenario simulation when there are issues of asymmetry to deal with. Where there is an asymmetry in potential revenues about a normal or median outcome the returns calculated on the assumption of the median demand outcome offers a poor guide as to the prospective return that may be expected. This is true whether the pipeline is regulated or not. However, if there is a concern that the regulatory framework itself gives rise to the asymmetry the approach offers a mechanism for dealing with it. This particular issue is covered further in appendix 3.

Finally, table A1.4 shows that the actual outcome may be significantly higher or lower than the regulatory rate of return with an achievable return on equity of over 18.0 per cent being consistent with an average expected return of 14.7 per cent.[94]

As a final step in the use of such simulations for regulatory purposes it is necessary to find the reference tariff that provides an expected rate of return equal to the CAPM based regulatory rate of return. This is found by a systematic adjustment of the initial tariff setting or the X factor so that the desired return on equity is the result of the average return on equity over a large number of simulations with the selected pipeline configuration.

[94] Some of the higher demand scenarios gave rise to an achieved return on equity over 19.0 per cent.

Appendix 2

Example of an adjustment to the initial capital base to reflect actual costs and the effect on reference tariffs

The ACCC considers the inclusion of a symmetric adjustment mechanism can accommodate any material variance between the forecast and final cost of the initial capital base (ICB); facilitate certainty regarding how under or over recovery of costs can be remedied; avoid potential discontinuities in the reference tariff price path to avoid volatility in tariffs; and provide certainty for users.

Clearly a range of appropriate adjustment mechanisms are possible and the optimal approach from a service provider's perspective is likely to depend on its own unique circumstances. The following illustrative examples set out a number of mechanisms that could be used.

Suppose that the pipeline is forecast to comprise two classes of asset A and B. A has an expected life of 50 years and B has an expected life of 20 years. Forecast costs for each class of asset is $100m each. Assume at the end of year two actual costs become known and expenditure on A is $120m and on B is $90m.

Reference tariffs would have been initially formed on the basis of the $100m forecast costs. The building block approach is used to establish the target revenues to derive the reference tariffs. See table A2.1.

- The WACC is assumed set at 8.00 per cent.

If the regulator had perfect foresight it would have used actual numbers for capex and obtained revenues as shown in table A2.2.

Perfect foresight is not available but at the beginning of year two or at the next convenient reset opportunity, tariffs and the regulatory asset base roll forward calculated can be adjusted in a mechanistic way to fully accommodate the error in capital expenditure estimates.

Table A2.1. Tariffs based on forecast capex costs

Regulatory asset base roll forward

Period	1	2	3	4	5	c/f RAB to next reset
Asset value at start of period						
Asset A ($m)	100.00	98.00	96.00	94.00	92.00	90.00
Asset B ($m)	100.00	95.00	90.00	85.00	80.00	75.00
Total RAB	200.00	193.00	186.00	179.00	172.00	165.00
Depreciation during period						
Depreciation on asset A	2.00	2.00	2.00	2.00	2.00	
Depreciation on asset B	5.00	5.00	5.00	5.00	5.00	
Total depreciation	7.00	7.00	7.00	7.00	7.00	
Building block components						
Return on capital (WACC 8%)	16.00	15.44	14.88	14.32	13.76	
Depreciation	7.00	7.00	7.00	7.00	7.00	
O&M	5.00	5.00	5.00	5.00	5.00	
Total (target revenue)	28.00	27.44	26.88	26.32	25.76	
Forecast volume (PJ pa)	30.00	31.00	32.00	33.00	34.00	
Average tariff ($/GJ)	0.933	0.885	0.840	0.798	0.758	
Initial expected net cash flows	23.000	22.440	21.880	21.320	20.760	178.2[1]
NPV of cash flows[1]	$200.00					

Note: 1. The NPV of net cash flows is valued at the start of period 1 and includes the value of the carried forward value of the RAB ($165m) at the end of period 5 (this value is shown in column 6 adjusted up to accommodate discounting between periods 5 and 6). A regulatory framework giving a prospective rate of return must have the NPV of net cash flows equal to the initial cost of the assets.

Table A2.2. Tariffs based on actual capex Costs

Regulatory asset base roll forward

Period	1	2	3	4	5	c/f RAB to next reset
Asset value at start of period						
Asset A ($m)	120.00	117.60	115.20	112.80	110.40	108.00
Asset B ($m)	90.00	85.50	81.00	76.50	72.00	67.50
Total RAB	210.00	203.10	196.20	189.30	182.40	175.50
Depreciation during period						
Depreciation on asset A	2.40	2.40	2.40	2.40	2.40	
Depreciation on asset B	4.50	4.50	4.50	4.50	4.50	
Total depreciation	6.90	6.90	6.90	6.90	6.90	
Building block components						
Return on capital (WACC 8%)	16.80	16.25	15.70	15.14	14.59	
Depreciation	6.90	6.90	6.90	6.90	6.90	
O&M	5.00	5.00	5.00	5.00	5.00	
Total (target revenue)	28.70	28.15	27.60	27.04	26.49	
Forecast volume (PJ pa)	30.00	31.00	32.00	33.00	34.00	
Average tariff ($/GJ)	0.957	0.908	0.862	0.820	0.779	
Net over-recovery using forecast figures in table A 2.1	-0.700	-0.708	-0.716	-0.724	-0.732	
Expected cash flows under option	23.700	23.148	22.596	22.044	21.492	189.54
NPV of cash flows	$210.00					

It is not necessary to track the errors in the depreciation building blocks and for the return on capital components to achieve this. All that is required is to observe the difference in revenues calculated under the two different sets of capex. The updated revenue estimates may be above or below those calculated initially. Where it is above, the initial revenue estimate is inadequate to provide both the necessary return on capital and provide for the planned path of depreciation. It is convenient to assume that all the shortfall is accounted for by a temporary stalling in the return of capital. Similarly, where updated revenues are below the initial estimates it is assumed there has been an excess over the planned rate of return of capital.

Under this interpretation all that needs to be done to re-validate the regulatory accounts is to explicitly recognise the accumulated excess/shortfall in the regulatory accounts and make adjustments to ensure that the integrity of the regulatory asset base roll forward is preserved.

This may be done in a number of ways that preserve the expected rate of return on investment calculated as appropriate in the initial regulatory decision.

Option 1. Allow an immediate change in tariffs to follow the price path calculated based on the actual capex data when it is available. This approach requires an adjustment of the regulatory asset base at the next regulatory reset to reflect the excess/shortfall in the return of capital carried forward and the potential return on that portion of capital. There is some discretion in deciding which class of assets should be subjected to the accommodating adjustment; however, an apportionment in

proportion to the written down asset value would seem fairly reasonable.[95] The adjustments relevant to the examples above are shown in table A2.3. It should be noted that the NPV of the cash-flows following these adjustments equates to the initial capital costs confirming consistency with the regulatory rate of return as an expected outcome.

Table A2.3. Option 1—Adjustments to remedy errors in forecast capex costs (assuming actual capex costs become known at end of period 2)

Period	1	2	3	4	5	RAB adjustment
Extra depreciation	-0.70	-0.71	0.00	0.00	0.00	0.00
Accumulated extra depreciation	-0.70	-1.41	-1.41	-1.41	-1.41	-1.41
Accum depr + return on it	-0.70	-1.46	-1.58	-1.71	-1.84	-1.84
Actual cost carried forward RAB						175.50
Modified carried forward RAB						177.34
Expected cash flows under option	23.000	22.440	22.596	22.044	21.492	191.5318
NPV of cash flows	$210.00					

Option 2. Allow the initial forecast price path to continue until the next regulatory reset. This is likely to lead to an increase in the excess/shortfall capital return. The principles used are the same as option 1 and require an adjustment to the carried forward value of the RAB. If the price changes are minor this may be the simpler approach. The main shortcoming of deferring any adjustment is that there may be a more significant tariff adjustment required in transition to the next regulatory period.

Table A2.4. Option 2—Adjustments to remedy errors in forecast capex costs (although actual capex costs become known at end of period 2 forecast price path is used until next reset)

Period	1	2	3	4	5	RAB Adjustment
Extra depreciation	-0.70	-0.71	-0.72	-0.72	-0.73	0.00
Accumulated extra depreciation	-0.70	-1.41	-2.12	-2.85	-3.58	-3.58
Accum depr + return on it	-0.70	-1.46	-2.30	-3.20	-4.19	-4.19
Forecast carried forward RAB						175.50
Modified carried forward RAB						179.69
Expected cash flows under option	23.000	22.440	21.880	21.320	20.760	194.0687
NPV of cash flows	$210.00					

Option 3. In principle it is possible to make an overcompensating adjustment in a move to the new price path so that by the end of the regulatory period any excess/shortfall capital return is reduced to zero. This avoids the need to make a further adjustment to the RAB carry forward value. These calculations are shown in table A2.5. The calculations recognise that the net over-recovery of depreciation needs to be undone over the remaining periods of the access arrangement. Such an approach is not generally favoured for those scenarios where the tariff path has relied

[95] Generally, assets within a regulatory framework are classified by function of the assets and the rate of depreciation (or economic life) assigned to those assets. In this context it is sufficient to classify assets according to their planned depreciation profile (or by expected economic life).

on smoothing or where volumes are changing rapidly as the revenue implications are complex and the necessary tariff adjustments much more difficult to assess.

Table A2.5 . Adjustments required under Option 3 —recalculating price path to accommodate forecast error to date and creating the carried forward RAB value consistent with knowing actual costs from the start (assuming actual capex costs become known at end of period 2)

Regulatory asset base roll forward

Period	1	2	3	4	5	CF RAB to next reset
Net over recovery of revenue	-0.7	-0.7				
Cumulative over-recovery at start of period	0.0	-0.7	-1.5	-1.6	-1.7	-1.8
Asset value at start of period						
Asset A ($m)	120.00	117.60	115.20	112.80	110.40	108.00
Asset B ($m)	90.00	85.50	81.00	76.50	72.00	67.50
RAB adjustment	0.00	0.00	1.46	0.98	0.49	0.00
Total RAB	210.00	203.10	197.66	190.28	182.89	175.50
Depreciation during period						
Depreciation on asset A	2.40	2.40	2.40	2.40	2.40	
Depreciation on asset B	4.50	4.50	4.50	4.50	4.50	
Notional extra depreciation	-0.70	-0.71	0.49	0.49	0.49	
Total depreciation	6.20	6.19	7.39	7.39	7.39	
Building block components						
Return on capital (WACC 8%)	16.80	16.25	15.81	15.22	14.63	
Depreciation	6.20	6.19	7.39	7.39	7.39	
O&M	5.00	5.00	5.00	5.00	5.00	
Total (target revenue)	28.00	27.44	28.20	27.61	27.02	
Forecast volume (PJ pa)	30.00	31.00	32.00	33.00	34.00	
Average tariff ($/GJ)	0.933	0.885	0.881	0.837	0.795	
Expected cash flows under option	23.000	22.440	23.201	22.610	22.019	189.54
NPV of cash flows	$210.00					

Note: Approximate values can be obtained by dividing the accumulated extra depreciation to date by the number of periods left. However, this ignores the return on that component of capital. In practice it is a simple matter to use the 'goal seek' values for depreciation which restore the ARB based on actual costs going into the next reset period.

Option 4. Finally, it is possible to acknowledge the error in revenues posed by the capex forecasts and recalculate the tariffs going forward accordingly. This is similar to option 3 in that there is a jump to a new price path. But because of any net over recovery of depreciation to date is not explicitly reversed the carried forward asset value is also modified. Despite the modifications on these two fronts the approach has appeal in that it best reflects an immediate recognition of the previous error and recalculates all future tariffs and asset values taking that error into account.

The relevant calculations are shown in table A2.6.

Table A2.6. Adjustments required under Option 3—recalculating price path to accommodate forecast error to date (assuming actual capex costs become known at end of period 2)

Regulatory asset base roll forward

Period	1	2	3	4	5	CF RAB to next reset
Net over recovery of revenue	-0.7	-0.7				
Cumulative over-recovery at start of period	0.0	-0.7	-1.5	-1.6	-1.7	-1.8
Asset value at start of period						
Asset A ($m)	120.00	117.60	115.20	112.80	110.40	108.00
Asset B ($m)	90.00	85.50	81.00	76.50	72.00	67.50
Cumulative RAB adjustment	0.00	0.00	1.46	1.46	1.46	1.46
Total RAB	210.00	203.10	197.66	190.76	183.86	176.96
Depreciation during period						
Depreciation on asset A	2.40	2.40	2.40	2.40	2.40	
Depreciation on asset B	4.50	4.50	4.50	4.50	4.50	
Notional extra depreciation	-0.70	-0.71				
Total depreciation	6.20	6.19	6.90	6.90	6.90	
Building block components						
Return on capital (WACC 8%)	16.80	16.25	15.81	15.26	14.71	
Depreciation	6.20	6.19	6.90	6.90	6.90	
O&M	5.00	5.00	5.00	5.00	5.00	
Total (target revenue)	28.00	27.44	27.71	27.16	26.61	
Forecast volume (PJ pa)	30.00	31.00	32.00	33.00	34.00	
Average tariff ($/GJ)	0.933	0.885	0.866	0.823	0.783	
Expected cash flows under option	23.000	22.440	22.713	22.161	21.609	191.12
NPV of cash flows	$210.00					

It should be noted that the validity of each option is confirmed by calculating the NPV of the resultant cash flows and the residual asset value carried forward to the next reset using the WACC as the discount rate. Under each option, for adjustment to take account of the error in capex forecast, the NPV should equal the actual cost of the assets at commencement of operations (start of period 1). Each of the four options outlined above are consistent with the building block approach and are confirmed by its NPV equivalence. Accordingly, from a financial perspective, a service provider should be indifferent between the four options.

Q&A

Question 1. Should the existence of foundation contracts alter the approach taken to these adjustments.

Answer 1. No. The tariffs in foundation contracts have been negotiated and are normally legally binding. They may include rise and fall clauses to accommodate unexpected changes in costs but these do not impinge on the regulatory calculations.[96]

Question 2. Suppose volumes and consequently revenues are quite different from those forecast as part of the regulatory decision. Does this alter the calculations that are required to adjust for updates in capital costs?

Answer 2. No. No adjustment would be made in such cases if there were no error in forecast capital costs. A shortfall or excess of revenues in such cases is part of incentive mechanism within the regulatory framework for the service provider to expand the market for its services. Those incentives must be preserved within the adjustment mechanism so it is only the target revenues emerging from the regulatory calculations that need to be factored into the adjustment

[96] Refer code section 2.25 and 6.15(e)

Appendix 3

Example of benefit sharing when demand exceeds a pre-set threshold

This appendix three builds on the framework demonstrated in appendix one in relation to determining expected demand and revenues in the face of uncertainty. In the event that an upside or downside outcome was realised during a regulatory period that was extreme or outside the range of outcomes reflected in the simulations, the regulator is required to consider sharing mechanisms.

This appendix provides an illustrative example of how such a benefit sharing mechanism may be designed in order to provide ex-ante certainty regarding its operation and effect on revenues subsequently realised beyond a certain point.

The framework in appendix one depended on assigning probabilities to the range of feasible outcomes. In general, there is no way of knowing whether the scenarios developed are free from bias and an observed actual demand outcome is a genuine random event consistent with the scenarios postulated. An exception to this is when an actual outcome is outside the range of the probabilistic scenarios considered. Such an outcome may or may not be a result of misrepresentation of likely scenarios. It does not matter whether the divergence is above or below the range of forecasts made. In either case, it is clear that the basis for establishing the reference tariffs was flawed and a reassessment warranted. However, such a reassessment poses a problem of principle linked to the need to use expectations at the time of financial close.

If demand turns out to be worse than envisaged in any of the scenarios there is already a mechanism available to reconsider regulated revenues since the code allows the service provider to seek a review at any time. However, this scenario too poses the same conflict of principle in that the risk based framework would be put aside.

If the outcome involves demand higher than any scenarios considered in establishing reference tariffs there is no mechanism by which the regulator can seek a review. A reset of tariffs based on actual blue sky demand 'ex post' is considered detrimental to incentives and is the main reason for establishing the framework such as that described in appendix 1.

Therefore, the regulatory framework needs to be able to cater for unexpected demand aberrations at the time of the initial assessment. This is because it is inconceivable that any probabilistic scenarios postulated in response to the deviant outcome could be viewed as an ex-ante expectation. Hence the concept of maintaining revenues on the basis of expectations held at the time of financial close would be lost. To cope with the situation a benefit sharing mechanism is proposed that enables customers to receive some of the benefits of greater than expected demand. To handle the symmetrical issue of demand short fall a parallel mechanism could also be proposed to allow the service provider to regain lost ground. In the case of high demand realisations, this could be achieved by reducing the proposed reference tariffs when

demand exceeds certain pre-set thresholds.[97] This will reduce some of the blue sky that may have been obtainable by the service provider, but if sharing is an anticipated possibility it the 'ex ante' net value of that blue sky

A benefit of such a mechanism is to reduce the incentive for a service provider to distort its view of anticipated demand outcomes. This is achieved because the benefit sharing mechanism is less likely to be triggered when forecasts are accurate. In this way the service provider gains greater certainty of expected returns in such circumstances by truthful revelation of demand scenarios. Such sharing is to occur in any period in which demand exceeds the preset threshold. A similar mechanism for sharing can be specified when there are shortfalls in demand.

A suggested mechanism

The threshold for sharing is derived from the scenarios used to establish the reference tariffs. The upper threshold demand trigger in period t, TU(t) beyond which sharing is to occur, is set equal to the average demand Dav(t) plus the standard deviation SD(t) of demand outcomes forecast for period t.

$$TU(t) = Dav(t) + SD(t) \qquad (1)$$

Beyond this level of demand the extra revenues achieved are to be shared with users through a rebate mechanism or a reduction in tariffs.

A low threshold demand trigger TL(t) can be similarly defined.

$$TL(t) = Dav(t) - SD(t) \qquad (2)$$

Below this level of demand the shortfall in revenues achieved are to be partially recovered in future tariffs.

The sharing could be on a 50/50 basis but a sliding scale could also be used. Such a rebate formula is given by:

$$Rebate(t) = (0.5 \times (D(t) — TU(t))/ D(t)) \times Revenue \qquad (3)$$

where D(t) is actual demand in period t.

Note that in this instance Rebate(t) represents a percentage of the revenue from demand serviced in year t and which needs to be rebated to customers.

A simple example

Suppose three scenarios are proposed initially each with equal probability. Each scenario starts with demand at 100 PJ pa in period 1. But in

[97] While this can be thought of as tariff moderation the benefit sharing may be achieved in practice by rebates or treating the excess return as a return of capital that will lead to a reduction in the value of the carried forward asset base at the next review.

scenario 1 demand grows at 2 PJ pa ie D1(t) = 100 + 2t PJ;
scenario 2 demand grows at 4 PJ pa ie D2(t) = 100 + 4t PJ; and
scenario 3 demand grows at 6 PJ pa ie D3(t) = 100 + 6t PJ.

Suppose for simplicity the reference tariff will be set at a constant price per GJ. The average scenario is scenario 2 and the standard deviation in period t is 1.6t PJ.

thus the upper trigger threshold demand path is given by:

$$TU(t) = 100 + 4t + 1.6t \qquad (4)$$

And the lower trigger threshold by:

$$TL(t) = 100 + 4t - 1.6t \qquad (5)$$

As shown in graph A3.1 the lower and upper thresholds are exceeded in scenarios 1 and 3 respectively. That is there will be an element of revenue sharing in these scenarios even though they are represented in the portfolio of possible scenarios postulated. This is not considered a problem since the revenue sharing mechanism is also integrated into the reference tariff framework described in appendix 1. The modification of the revenues is taken into account when establishing the reference tariff, which may be somewhat higher or lower than it otherwise would have been. In this case the symmetry in the demand scenarios means that the middle or average scenarios would give rise to the same reference tariff as using the probabilistic scenarios. However, in the example below part of this symmetry is lost because demand exceeds pipeline capacity in scenario 3 in periods 9 and 10.

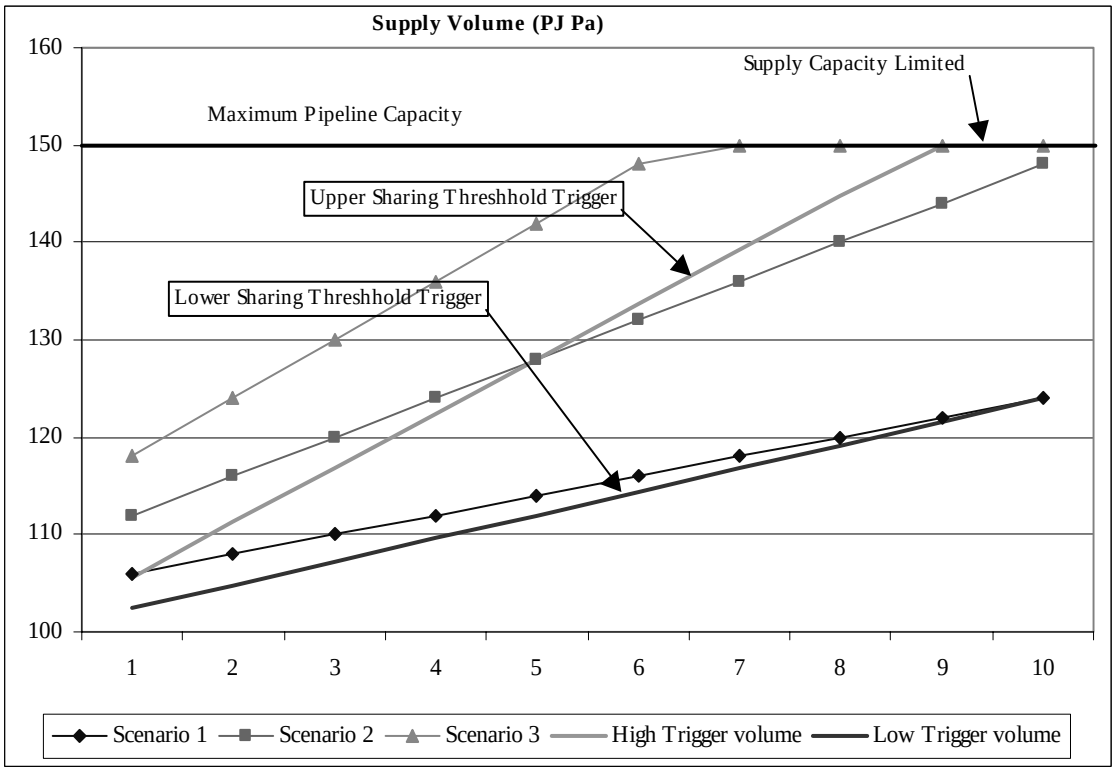
Assumptions:

Target WACC is set at 8.00 per cent;
The initial capital cost is $800m;
The residual asset value after 10 years is $700m;
Maximum pipeline capacity 150 PJ per year; and
O&M costs are a constant $25m per year.

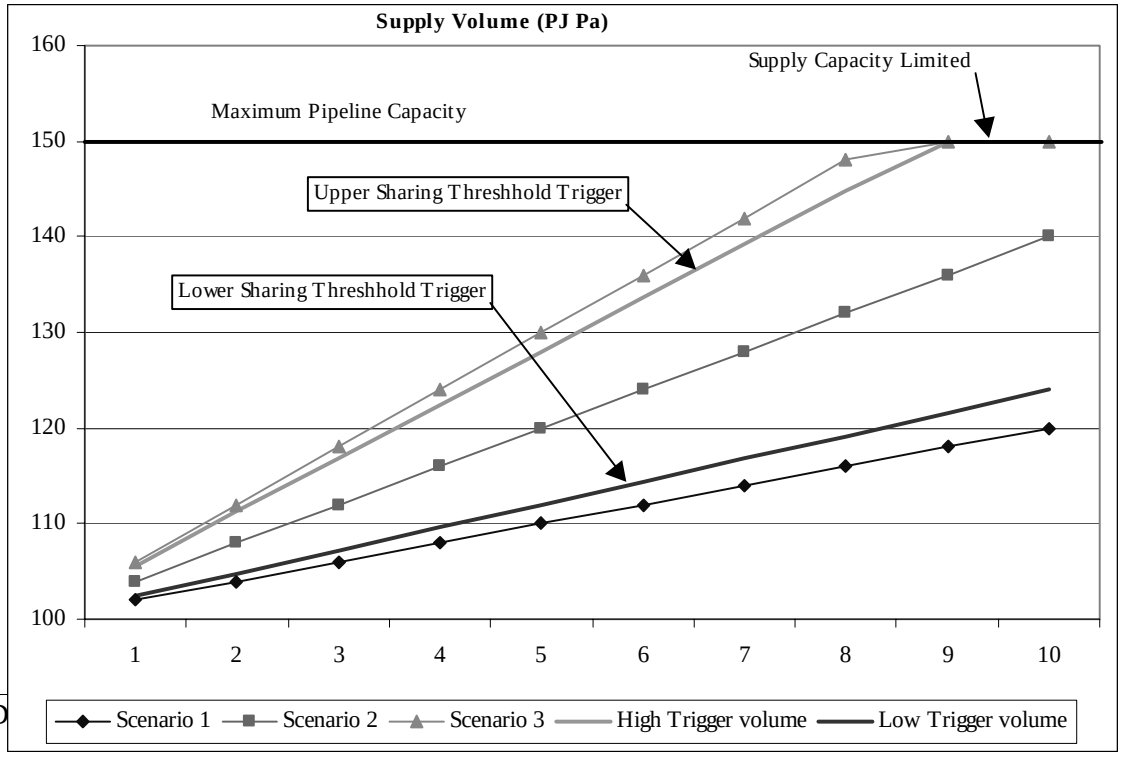
Cash flow modelling shows that the reference tariff consistent with these assumptions and the assumed level (50 per cent) of benefit sharing $0.8047 per gigajoule. With different sharing levels the reference tariff may vary but because of the symmetry in demand scenarios the variations in this example as shown in Table A3.1 below are minor. With zero sharing the reference tariff would be $0.8040 per gigajoule and with 100 per cent sharing $0.8054 per gigajoule.

{DN XXXX Editor graphs A3.1 and A3.2 need to be switched around}

Graph A3.1. Demand volumes forecast under the three scenarios and high and low trigger volumes for revenue sharing



Graph A3.2. Demand volumes under the three corresponding scenarios but with demand brought forward by two periods, original high and low trigger volumes for revenue sharing are also shown



D

Under scenarios 1 (low demand) and 3 (high demand) a mild amount of revenue sharing is already occurring. As shown in graph A3.1 and table A3.1, this is reflected in the achieved rate of return with sharing featured. Graph A3.2 illustrates what could happen in the future if demand increases more than expected (in this case illustrated by bringing demand forward by two periods. The extent by which actual demand exceeds the trigger volume line indicates the amount of sharing. For example under a 50 per cent sharing mechanism the revenues achieved in a year would be as if demand was midway between the actual demand and the trigger value. A similar picture of demand shortfall is produced by assuming demand growth is delayed by two periods.

Table A3.1 shows the actual return that would be achieved under each outcome and sharing assumption.

Table A3.1. Impact of revenue sharing on achievable returns under alternative scenarios

Ex ante expectations of achievable rate of return on assets					
Percent sharing %	0	25	50	75	100
Ex ante expectations of return on assets					
Scenario 1	7.03%	7.08%	7.13%	7.17%	7.22%
Scenario 2	8.04%	8.04%	8.03%	8.03%	8.02%
Scenario 3	8.92%	8.88%	8.84%	8.80%	8.76%
Average return (%)	8.00%	8.00%	8.00%	8.00%	8.00%
Reference tariff($/GJ)	0.8054	0.8051	0.8047	0.8044	0.8040
Rate of return achievable on assets with increased demand with above reference tariffs (brought forward two periods earlier than expected)					
Percent sharing %	0	25	50	75	100
Achievable rates of return on assets					
Scenario 1	7.43%	7.43%	7.43%	7.43%	7.43%
Scenario 2	8.83%	8.78%	8.73%	8.67%	8.62%
Scenario 3	9.84%	9.56%	9.30%	9.03%	8.76%
Average return (%)	8.70%	8.59%	8.48%	8.38%	8.27%
Rate of return achievable on assets with reduced demand with above reference tariffs (market growth delayed by two periods)					
Percent sharing	0	25	50	75	100
Achievable rates of return on assets					
Scenario 1	6.63%	6.78%	6.92%	7.07%	7.22%
Scenario 2	7.26%	7.26%	7.26%	7.26%	7.26%
Scenario 3	7.88%	7.88%	7.88%	7.88%	7.88%
Average return	7.26%	7.31%	7.35%	7.40%	7.45%

Other points to note from the simulations are as follows.
As expected, the effect of the sharing is to bring the returns under the extreme demand scenarios closer to the average expectation.

Regardless of the proportion of sharing proposed it is always possible to find the tariff that provides an ex ante expectation of the required 8 per cent return on assets.

This tariff decreases slightly with the level of sharing assumed because the sharing moderates the downside scenario more than the upside that is capped by the capacity constraint.

Without sharing (i.e. sharing of 0 per cent) the impact of an unexpected surge in demand is to increase achieved revenues and achieved return on assets. Similarly, a shortfall in demand reduces returns.

The increase in achieved returns is moderated by the impact of the sharing mechanism with the extent of moderation depending on the level of sharing specified. Returns are similarly stabilised when demand falls.

Where the sharing mechanism is not triggered under a scenario there is no change in return from what would be observed in the absence of benefit sharing.

At the extreme in scenario 3 when the trigger was already operating without the demand surge, the impact of 100 per cent sharing is to prevent any additional returns being achieved by the service provider. A similar effect is observed in scenario 1 in conjunction with the shortfall in demand expectations (the 100 per cent sharing example is included as illustration only and is not a proposed sharing setting).

- In all cases (apart from the last) the service provider retains an incentive to pursue market expansion as a means of increasing profits.

This example does not specify how the benefit sharing takes place. Different approaches may be applicable in different circumstances. The following are examples.

- Where additional demand (or demand shortfalls) can be anticipated in advance of annual price adjustments for CPI the actual tariff for the year ahead could be reduced/increased by the amount that reduces/increases revenues by the amount of the sharing.

- Where demand cannot readily be anticipated the benefits could be shared by providing appropriate rebates to customers at the end of the accounting year.

- Where it is difficult to anticipate demand, and where it is difficult to arrange end of year balancing arrangements or rebates (e.g. it would be difficult to extract additional charges from customers at the end of the year), an adjustment could be made to the residual value of the asset base to reflect the over or under recovery of revenues. When the residual is augmented, the revenues are subsequently recovered in future regulatory periods after the next regulatory review.[98] When the

[98] This is similar to the economic depreciation approach proposed for the Central West Pipeline where loss or under recovery of revenues because of low demand in early years is compensated by capital appreciation of the regulatory asset base to allow eventual recovery when the market matures.

residual value is reduced (customers paid too much) customers receive reduced tariffs in the future as compensation.

The choice of mechanism is more a matter of practicality rather than being a matter of regulatory principle.

Appendix 4

Summary of consultancies

Macquarie Bank Limited

'Issues for debt and equity providers in assessing greenfields gas pipelines'

Introduction

Macquarie Bank Limited (MBL) was engaged to advise the ACCC on what information would generally be required by debt and equity providers in assessing a greenfields natural gas transmission pipeline project. The report describes MBL's opinion, based on its experience of the Australian energy market.

Key findings

Debt holders require information on all the risks associated with the project. This enables the debt holder to assess the risk profile of the project and determine the amount, and cost, of debt that can be made available to the project. Equity holders also assess the risk profile of the project to determine their capital contribution, its structure and their required rate of return.

A single purpose company or trust is often established as the 'project vehicle' to undertake a pipeline project. This has the benefit of quarantining the project risks from the parent business. The project vehicle will then seek to minimise its cost of capital by maximising the relatively less expensive debt component. It should be noted that the source of funds from the domestic banking market is generally limited to $1 billion. Funds will also be limited by each bank's exposure to the project and the industry as a whole. Funding from the capital markets can be more cost effectively used once projects have moved from the construction phase to the operation phase. In addition, if a business is able to obtain an investment grade credit rating from a recognised agency and meets the credit criteria of the monoline insurers then it may be able to utilise 'credit wrapping'.

MBL advises that equity participants of a project generally determine their contribution to the business' capital with regard to their required rate of return for an investment with the specific risk profile and the time horizon for the investment. An equity holder generally seeks to maximise the nominal after-tax return from the project's cashflows. While equity holders use a similar approach to risk assessment as debt providers, they may be willing to assume a higher risk and make more aggressive assumptions.

MBL identified 14 specific risk categories that would be considered in a debt financing assessment. These included the following.

- **Construction risk**. Large pipelines are very sensitive to construction risk as they have a considerable period when revenue is not earned but borrowings are accruing interest. Debt providers seek to ensure that contractual arrangements allocate responsibilities and risks appropriately over this time.

- **Market and revenue risk**. While debt providers consider the extent that a pipeline has foundation contracts established in forming a view on the debt available for a project, equity providers are more likely to take the risk that the pipeline's market will not develop as predicted. This risk increases with the greater proportion of capacity that is uncontracted.

- **Interest rate and inflation**. Debt providers require pipeline companies to use interest rate hedges to reduce the extent of risk and improve cashflow certainty. If debt providers consider that a regulator will redetermine the business' return at the end of the regulatory period then they will require interest rates to be hedged to this date.

- **Regulatory risk**. In considering the cashflows of the new pipeline, debt providers will form their own view on whether the pipeline will be regulated and the nature of the regulatory framework. This view is formed with reference to (amongst other things) previous regulatory decisions in Australia for a variety of businesses. If the regulatory regime is clear and a high level of confidence can be established regarding the cashflows, including the regulator's assessment of the forecasts, then the risk profile of the business will decrease.

In assessing the various categories of risk, financiers may rely upon expert advice from a range of independent consultants, for example to provide assistance in developing forecasts in regard to the regulatory price paths and the supply and demand for gas. Debt providers may rely upon an expert engaged by a service provider or may appoint their own. They may also require independent certification of construction costs and operating and maintenance and capital expenditure forecasts. In some instances debt providers have in-house expertise. Reports will also be required from independent parties concerning the accounting, tax and legal aspects of the project.

Any issues identified by the consultants will be discussed by the debt providers with equity providers and the results will be incorporated into the debt providers financial model and/or the terms and conditions of the debt facility. All the required experts' reports must be specifically addressed to each debt provider. The debt providers will be relying on the reports for their lending decisions and must be able to have legal recourse to the expert for incorrect information.

Davis and Handley

'Cost of capital for greenfields investments in pipelines'

Introduction

Kevin Davis and John Handley[99] prepared a report for the ACCC that considered the appropriate determination of the cost of capital for greenfields investments in gas transmission pipelines. Specific questions to be addressed at the request of the ACCC included:

1. Whether the CAPM is an appropriate framework for assessing the WACC facing a greenfields pipeline.

2. How should risks that are specific to the project be recognised and compensated? For example, the level of return that may accrue to a greenfields pipeline is more uncertain than the returns to a mature pipeline owing to variation in financial parameters during development and construction (such as exchange rates), construction cost variability, operating cost variability (including teething problems) and demand uncertainty (beyond foundation contracts).

3. Whether the CAPM should be augmented to account for the specific risks facing a greenfields pipeline. Specifically, is it appropriate to inflate the beta and, if so, over what period should the inflated beta operate.

4. Whether it is appropriate to utilise a single beta for the pipeline industry as a whole, or whether separate betas should be developed for mature and greenfields pipelines. Is there a case for separating cash flow streams (for example, foundation contracts and speculative demand) and applying different WACCs to each.

5. Subject to the views regarding 1 to 4 above, does a CAPM approach to determining WACC and compensating specific risks in cash flows provide adequate compensation for potential downside risks.

Key findings

Davis and Handley conclude that the CAPM model is an appropriate framework for assessing the appropriate WACC facing a greenfields pipeline project. Noting that while there are a number of alternative approaches to the CAPM framework'none of

[99] Kevin Davis is Commonwealth Bank Group Chair of Finance, Department of Finance, The University of Melbourne. John Handley is Senior Lecturer, Department of Finance, The University of Melbourne.

the alternative approaches have surpassed the CAPM in popularity or use in practice' at this time.

Project finance techniques and financial engineering/risk management techniques are typically used (or are available) to reduce specific risks or pass such risks onto those willing and able to bear them at least cost. Provided that the capital base concept adopted for use in regulatory price determination reflects the cost of such risk transfer, or that the cash flows required to insure or hedge such risks are reflected in operating costs, no further adjustment for risk would appear to be warranted.

Specific, that is non-systematic, risks associated with a greenfields pipeline should not lead to an adjustment of beta—which is intended to reflect systematic risks only. Any such adjustment would be ad hoc and could lead to significant biases.

Davis and Handley note the issues involved in determining an appropriate beta for the purposes of regulating an asset. The suggestion that the beta for greenfields pipelines should be higher than the beta used for established pipelines is considered. In the absence of regulation the authors note there are some grounds for believing that the systematic risk of a greenfields pipeline may be somewhat higher than that of a mature pipeline. The authors suggest that the most significant factor is the long time frame over which cash flows are expected (that is, the cash flows are distant). However the authors also note that the regulatory approach to access pricing (eg redetermining access prices periodically; loss carry forward provisions; and the requirement of the code to use the actual construction costs of a new pipeline as the initial capital base) and the arrangements contained in foundation contracts may reduce this effect.

While it is, in principle, possible to decompose cash flow streams into foundation contracts and non-contract components with different risk characteristics, the practical problems of applying such an approach appear to make it infeasible.

Time lags are involved in construction before cash inflows are realised, and project viability requires that those outlays should be compounded at the required rate of return in determining the cost base of the project.[100]

Finally, the authors stressed that access prices derived on the basis of applying a required rate of return to an accounting asset base (at some date 2), conditional on an assumed level of future output which is different to that expected at the time the investment was made (date 1), are not necessarily compatible with providing appropriate signals for investment. If it is possible that the investment will ex-post (that is, at date 2) have a negative NPV resulting from low demand, and that access will only be sought in cases where demand is high, it is necessary that in that latter

[100] For example, if a project involves an outlay of $1 at date 0, has a required rate of return of r, and generates no cash flows until date 2, the required cash inflow at date 2 is $\$1(1+r)^2$ if the project is to have a zero NPV. If target cash flows at date 2 are to be determined at date 1, the appropriate capital base for use at that date is $1(1+r).

(high demand) case the ex-post (date 2) NPV will need to be positive if the ex-ante (date 1) NPV is to be zero.

Davis and Handley suggest one potential solution to this problem. That is, bring forward the coverage or access determination date so that it occurs early in the project appraisal and development or construction stage rather than after project success has been observed.

National Economic Research Associates (NERA)

Foundation contracts and 'greenfields' gas pipeline developments: experience from the US and other jurisdictions

Introduction

NERA was engaged to prepare a report on the role of foundation contracts in new gas pipeline developments in various relevant jurisdictions.

The report was required to address the following.

1. Typical foundation contracts established in overseas jurisdictions. This analysis drew primarily on experience in the United States, and to a lesser extent, experiences in other jurisdictions such as Singapore, Mexico, Argentina, UK etc.

2. Typical construct of a foundation contract. For example, usual terms and conditions, pricing formulae etc.

3. What is the normal relationship between foundation contracts and pipeline capacity (initial and potential) to justify the construction of the pipeline.

4. The incidence of most favoured nation (MFN) clauses in foundation contracts and common variants.

5. The incidence of provisions for blue sky sharing in foundation contracts. Description of typical benefit sharing mechanisms employed in foundation contracts.

6. Extent of regulatory oversight of foundation contracts including criteria employed by FERC to determine whether greenfields gas pipelines should be regulated or unregulated. Description of the nature of regulation applied to greenfields pipelines by FERC.

7. Use of market based tariffs in establishing foundation contracts (for both regulated and unregulated pipelines) and as a basis for determining third party access prices.

8. Level of security provided in foundation contracts.

Key findings

NERA's report focuses on the regulation of the gas pipeline industry in the US, and in particular, FERC's regulatory role. FERC has regulatory oversight for interstate pipelines and major interstate pipeline developments. This does not appear, in NERA's view, to have hindered the development of the pipeline industry to an extensive network.

New pipelines and extensions of existing interstate pipelines must obtain a 'certificate of public convenience and necessity' from FERC before being built. NERA considers that the application of an established set of tests in this process provides the industry with certainty.

Long-term contracts for the proposed pipeline projects are an important aspect of the certification process. The contracts underpin the new investment, sharing the long-term investment risks between the pipeliner and the user. The existence of long-term contracts increases the likelihood that the pipeliner's application will be approved and a certificate granted. However, they do not guarantee a certificate.

A feature of US contracts between service providers and users is the inclusion of a fixed charge to recover the investment costs and a variable charge for the marginal costs. NERA notes that as a result of this approach to tariffs there are no formal benefit sharing mechanisms or approaches to deal with blue sky. This contrasts with Australia where volume-based tariffs create the potential for blue sky to occur.

In addition, pipeline contracts in the US do not include most favoured nation' clauses. NERA notes that the inclusion of these clauses in foundation contracts has the effect of limiting the capacity utilisation of the pipeline and, consequently, the market will develop more slowly. The overall efficiency of new pipeline investment is likely to be sub-optimal. In contrast, FERC encourages price discrimination by pipeline service providers with the view to increasing the utilised capacity of the pipeline.

NERA notes that the code appears to be flexible enough to tackle most of the perceived problems associated with new gas pipeline developments in Australia.

Appendix 5

Summary of code provisions that facilitate regulatory certainty

This summary is based on an extract of material from the NERA consultancy, *Natural Gas Pipeline Access Regulation, 31 May 2001*[101]

1. **Section 2, Due process**. Due process is fundamental to regulatory certainty. Section 2 defines the code's provision of due process to the service provider and interested parties. The service provider receives a fair hearing, a decision with reasons, rights of appeal, and a transparent process. Various parties have complained about not being able to examine the actual tariff model of the companies regulated under the code, but NERA feels that there is movement in this direction. These provisions, along with the high level of detail specified in the code, protect the service provider from regulatory caprice.
2. **Section 2.21, Timely regulatory rulings**. Section 2.21 (subject to 2.22) provides that the regulator must issue a final decision within six months of receiving a proposed access arrangement, ensuring that the service provider is not left in limbo indefinitely. Six months is a reasonable length of time, given the long lead times inherent in gas pipeline investments and time needed for consultation and due process. Section 2.43 (subject to 2.44) continues this process for appeals and revisions. Any delays in issuing an access arrangement final decision is likely to be a concern for providers of capital. To mitigate timing uncertainties for regulatory decisions regarding greenfields pipeline projects it is incumbent on project proponents to pro-actively manage regulatory determination processes to ensure regulators are able to promulgate determinations within the minimum prescribed timeframe.
3. **Section 2.24, Protecting interests**. The ACCC, as relevant regulator, is charged with the task of balancing the different interests of parties affected by the services offered on the pipeline, and the terms and conditions on which those services are offered. Accordingly, in assessing an access arrangement the ACCC must consider the interests of the service provider, users, and the public interest. However, it cannot ignore or abrogate the service provider's existing contractual obligations. The factors it must consider are (inter alia):

   (a) the service provider's legitimate business interests and investment in the covered pipeline

[101] This summary is based on an extract of material from the NERA consultancy, *Natural Gas Pipeline Access Regulation* (pp. 14-19). 31 May 2001. This summary should not be interpreted as legal advice on the interpretation, effect or scope of the sections quoted. Should further clarification be required readers should seek their own legal advice.

(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.

4. **Section 2.50, Allowance for negotiated arrangements**. Section 2.50 (as well as the preface to section 8) allows for a variety of pricing structures. The code allows pipelines and customers to negotiate any alternative arrangements upon which they both agree. 'The Reference Tariff Principles are designed to provide a high degree of flexibility so that the Reference Tariff Policy can be designed to meet the specific needs of each pipeline system.'[102] However, coverage under the code is meant to limit the exercise of pipeline monopoly power, by capping pipelines' charges at their efficient costs, in aggregate. Pipelines have great latitude in price setting, subject to this restriction.

5. **Section 3.16(b), Pricing expansions**. Section 3.16(b) sets out the pricing policy for future investments in expansions/extensions (subject to 8.25 and 8.26, discussed below). Thus, when making commercial decisions the service provider and its users can know how any prospective future investments will be priced.

6. **Sections 3.18 and 3.19, Access arrangement duration**. Sections 3.18 and 3.19 allow for an access arrangement duration of any period. While five years is the default expectation, it is explicitly **not** required. Where an access arrangement period is longer than five years, the regulator must consider whether mechanisms should be included to address the risks of forecasts proving incorrect. A new pipeline seeking a longer duration (e.g. 10 years) could receive one under the code's provisions, provided it can satisfactorily support its request. A longer initial access arrangement period may be desirable to the service provider, as it can provide greater certainty for a longer period of time over the price path the company will use for its regulated services.

7. **Section 6, Foundation shippers**. The preface to section 6 recognises the importance of contractual rights, including contracts held by 'foundation shippers.'[103] The code enables these arrangements to proceed without interference.

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[102] Section 2.50 states: 'For the avoidance of doubt, nothing (except for the Queuing Policy) contained in an access arrangement (including the description of services in a services policy) limits: (a) the services a service provider can agree to provide to a user or prospective user; (b) the services that can be the subject of a dispute under section 6; (c) the terms and conditions a service provider can agree with a user or prospective user; or (d) the terms and conditions that can be the subject of a dispute under section 6.'

[103] 'Because the arbitrator cannot deprive a person of a contractual right, 'foundation shippers' contracts cannot be overturned by the arbitrator at either the service provider's or foundation shipper's request.'

8. **Section 6, Dispute resolution**. Section 6 of the code sets out a formal dispute resolution mechanism. It provides the pipeline with the confidence that disputes will be adjudicated in a predetermined process. The code lays out guidelines, restrictions, and a formal procedure for the dispute arbitrator, protecting the pipeline from arbitrary, capricious, or confiscatory decisions.
9. **Section 6.15, Guidance for the arbitrator**. Section 6.15 of the code requires that the disputes arbitrator must take into account (inter alia):

   (a) the service provider's legitimate business interests and investment in the covered pipeline

   (e) firm and binding contractual obligations of the service provider or other persons (or both) already using the covered pipeline

   (f) the operational and technical requirements necessary for the safe and reliable operation of the covered pipeline

   (g) the economically efficient operation of the covered pipeline.

   Under Section 6.15, the arbitrator must also take into account 'the costs to the service provider of providing access.'
10. **Section 6.18, Restrictions on decisions**: Section 6.18 limits the type of decisions an arbitrator can make, including decisions which that impede the rights of existing users to obtain services, and any decision which that requires the service provider to provide services or any tariff other than a reference tariff.
11. **Section 8, Reference tariffs**. Section 8 specifies the method for setting prices, the costs that will be examined and how they will be examined, and a formal process for doing so. These tariff principles give a company's investors considerable certainty regarding their return on investment. While not **guaranteeing** revenues, the tariff principles ensure that the company has a fair opportunity to earn them.
12. **Section 8.3, Form of regulation**. Section 8.3 allows the service provider two alternatives for setting prices: a 'price path' or 'cost of service.' The price path approach assures the company of the prices it can charge for the duration of the access arrangement (which could be greater than five years). The cost of service approach adjusts the company's prices 'continuously in light of actual outcomes … to ensure that the tariff recovers the actual costs of providing the service.' The pipeline decides which alternative to propose; thus, it can select whichever one it deems fits its best interests. A service provider wanting a 'hands off' regulatory arrangement can request it while a company wanting greater certainty of cost recovery can request that instead.
13. **Section 8.4, Total revenue**. Section 8.4 provides three alternative methodologies for calculating the revenue target. Like section 8.3, this section offers the certainty of a cost-of-service-based revenue target methodology, including a return on the asset value and an allowance for inflation (section 8.5). The alternative methodologies—internal rate of return and net present value—are meant to provide the same result. From the total revenue determination, reference tariffs are calculated to provide that revenues match costs.

14. **Section 8.12, Initial capital base, New pipelines**. Section 8.12 states that the initial capital base will be valued by the actual costs of the asset and that these costs will be used to set reference tariffs (Section 8.8). These provisions protect the service provider from the sorts of downward revaluations that could result from the application of hypothetical or theoretical asset valuation methodologies. At the same time they protect customers from the exercise of market power by a pipeline. Still, pipelines and their customers are free to negotiate other prices, and foundation customer contracts remain protected. The side-by-side existence of these provisions—cost-based prices and the freedom to negotiate—provides pipeline companies and their customers with a combination of regulatory and commercial freedom.

15. **Section 8.14, Rolling the asset base forward**. Section 8.14 builds on section 8.12, determining the means by which the asset base will be valued at the expiry of one access arrangement period and the commencement of a subsequent one. Section 8.14 states that the rolled-forward asset base will be:

    > … the Capital Base applying at the expiry of the previous Access Arrangement adjusted to account for the New Facilities Investment or the Recoverable Portion (whichever is relevant), Depreciation and Redundant Capital (as described in section 8.9) as if the previous Access Arrangement had remained in force.

    In other words, when establishing a new access arrangement, the regulator cannot apply an alternative methodology that would decrease (or increase) the asset value.

16. **Section 8.16, Pricing capacity expansions**. Section 8.16, along with sections 8.25 and 8.26, allows for expansion capacity to be priced at either: (1) the price level of existing capacity, without necessitating a review of access arrangements; or (2) a surcharge to both existing customers and new ones, where benefits accrue sufficiently to existing customers. Allowing for expansions to be priced at the existing price level can provide regulatory certainty to pipelines regarding the price level. Similarly, a predefined set of rules for increasing reference tariffs at expansions provides certainty about how investment cost recovery will take place.

17. **Section 8.19, Speculative investment**. Section 8.19 of the code deals with pipeline investments over and above the amount of investment in new facilities that would go into the capital base. This section allows for the creation of a speculative investment fund that can later be put into the capital base when these assets are called for. Until that time the capital invested is held in this account and can accrue a rate of return on that investment, which will also be collected when the investment amount is put into the capital base. This regulatory 'hold account' is a flexible, powerful provision. A service provider that anticipates future increases in demand beyond current amounts can make a large investment all at once—taking advantage of scale and scope economies—without the excess amount of its investment being declared imprudent and written down. This is an important provision for providing investors with regulatory certainty. At the same time it protects existing customers from paying the costs of spare capacity.

18. **Sections 8.30 and 8.31, Rate of return**. Sections 8.30 and 8.31 of the code set out the mechanism by which pipeline investors recover the costs **on** an

investment—i.e. the rate of return on regulated pipeline investments—specifying clearly that the methodology used

> should provide a return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the Reference Service. (Section 8.30)

Section 8.31 specifies, via an example, how this can be carried out to satisfy the code's requirements. Specifying the rate of return methodology provides an important degree of regulatory certainty to investors by ensuring that they will not be subject to regulatory hold-up through either an outright denial of a return on their investment, or of a methodology that fails to reflect the risks inherent in the business—a universal concern of pipeline investors. The ACCC/ORG cost of capital forum (3 July 1998) produced considerable valuable evidence on cost of capital procedures. The conclusions from that forum have been referenced in many subsequent regulatory decisions in Australia, and they provide a reliable basis for calculating the cost of capital in the future.

19. **Section 8.32 and 8.33, Depreciation**. Section 8.32, on depreciation, sets out rules for the mechanism by which pipeline investors recover the costs **of** an investment. Depreciation methodologies are another means by which investors' money can be put at risk by a bad regulatory regime. The failure to specify a depreciation practice, or to specify one that is vague or subjective, can result in regulatory expropriation of investors' funds. The code addresses these concerns head-on by specifying that a regulated asset is fully depreciated once, and only once, over its economic life. In this way the code strikes a balance in which investors recover the costs of their investments, and customers are protected form the exercise of monopoly power.

20. **Section 8.43, Discount practices**. Section 8.43 of the code allows, under certain specified conditions, for the service provider to extend discounts to price-sensitive customers, and recover the otherwise foregone revenues from its other customers. This provision of the code provides a means by which efficient usage of the pipeline can be furthered—through avoiding having a pipeline sit with idle capacity—while not leaving the pipeline with a revenue shortfall. In sum, even after discounting to price-sensitive customers who would otherwise not take pipeline service, target revenues continue to match the pipelines' costs.

21. **Sections 8.47 and 8.48, Fixed principles**. Sections 8.47 and 8.48 deal with Fixed principles. These provide a means of establishing certain aspects (structural elements) of regulatory certainty across access arrangement periods. In this way a service provider seeking certain provisions to be sustained over a long term can do so without necessarily having to propose a very long access arrangement duration.

    Structural elements specifically include 'the depreciation schedule, the financing structure, and that part of the rate of return that exceeds the return that could be earned on an asset that does not bear any market risk.' These provisions can provide investors with long-term regulatory certainty over how their investment will be treated. The provisions clarify parameters over which the regulator might otherwise seek to exercise discretion and which could leave investors unclear about future regulatory changes.

Appendix 6

Glossary

ACCC	Australian Competition and Consumer Commission
Access arrangement	Arrangement for third party access to a pipeline provided by a pipeline owner and/or operator and submitted to the relevant regulator for approval in accordance with the code
Access arrangement information	Information provided by a service provider to the relevant regulator pursuant to section 2 of the code
Access arrangement period	The period from when an access arrangement or revisions to an access arrangement takes effect (by virtue of a decision pursuant to section 2) until the next revisions commencement date
the Act	*Gas Pipelines Access (South Australia) Act 1997*
AGA	Australian Gas Association
Bare transfer	When the terms of a contract with a service provider are not altered as a result of transfer or assignment of capacity rights
CAPM	Capital asset pricing model
COAG	Council of Australian Governments
Code	*National Third Party Access Code for Natural Gas Pipeline Systems*
	■
Covered pipeline	Pipeline to which the provisions of the code apply
CPI	Consumer price index
CPI-X	An adjustment that provides an automatic mechanism for adjusting tariffs to take account of ongoing inflation and provides for the corresponding changes in rates of return observed in commercial markets
CWP	Central West Pipeline
Derogation	A legislative exemption from compliance with specified obligations set out in the code

Duke	Duke Energy International
EGP	Eastern Gas Pipeline
Energy Users	Energy Users Association of Australia
E_D	Expected demand
FERC	Federal Energy Regulatory Commission
Gas Code	*National Third Party Access Code for Natural Gas Pipeline Systems*
GJ	GigaJoule
Greenfields pipeline	For the purposes of this guideline, a greenfields pipeline is considered to encompass both proposed pipelines and new pipelines, the market for the output of which was previously non-existent
Guideline	*Greenfields guideline for natural gas transmission pipelines*
ICB	Initial capital base
MFN	Most favoured nation
Mpa	Megapascal (unit of pressure)
NCC	National Competition Council
NERA	National Economic Research Associates
NPV	Net present value
OffGAR	The Office of Gas Access Regulation, Western Australia
Part IIIA	Part IIIA of the *Trade Practices Act 1974*
PCCM	Project cost containment mechanism
PJ	PetaJoule (equal to 1 000 000 GJ)
PTRM	Post tax revenue model
Queuing policy	A policy for determining the priority that a user, or prospective user has, as against any other user, or prospective user, to obtain access to spare capacity

Reference service	A service that is specified in an access arrangement and in respect of which a reference tariff has been specified in that access arrangement
Reference tariff	A tariff specified in an access arrangement as corresponding to a reference service and which has the operation that is described in sections 6.13 and 6.18 of the code
ROE	Return on equity
Reference tariff policy	A policy describing the principles that are to be used to determine a reference tariff
Revisions commencement date	The date upon which the next revisions to the access arrangement are intended to commence
Revisions submissions date	The date upon which the service provider must submit revisions to the access arrangement
Service	A service provided by means of a covered pipeline including: (a) haulage services (such as firm haulage, interruptible haulage, spot haulage and backhaul) (b) the right to interconnect with a covered pipeline (c) services ancillary to the provisions of such services but does not include the production, sale or purchasing of natural gas
Service policy	A policy detailing the service or services to be offered.
Service provider	The person who is the owner or operator of the whole or any part of the pipeline or proposed pipeline
Shipper	An alternative term generally used in this guideline to describe an existing user of the pipeline
SFV	Straight fixed variable
TJ	Terajoule (equal to 1 000 GJ)
TPA	*Trade Practices Act 1974*

Vanilla WACC	The nominal weighted average of the cost of equity and debt to the business before any adjustments for taxes and change in the general level of prices Vanilla WACC = $E/V.R_e + D/V.R_d$ Where R_e is the post-tax cost of equity determined by the CAPM formula and R_d is the pre-tax nominal cost of debt.
WACC	Weighted average cost of capital

Appendix 7

Related publications

ACCC, *Access regime—a guide to Part IIIA of the Trade Practices Act*, November 1995.

ACCC, *Draft statement of principles for the regulation of transmission revenues*, May 1999.

ACCC, *Access undertakings—a guide to Part IIIA of the Trade Practices Act*, September 1999.

ACCC, *Access arrangement by AGL Pipelines (NSW) Pty Ltd for the Central West Pipeline final decision*, June 2000.

ACCC, *Post tax revenue handbook*, October 2001.

The Brattle Group, *Third-party access to natural gas networks in the EU*, March 2001, p.24.

Commonwealth of Australia, Gas Reform Task Force 1996, *National Third Party Access Code for Natural Gas Pipeline Systems*.

Davis, K and Handley, J, Report on *Cost of capital for greenfields investment pipelines*, February 2002.

Macquarie Bank Limited, *Issues for debt and equity providers in assessing greenfields gas pipelines*, March 2002.

National Economic Research Associates, *Regulation of tariffs for gas transportation in a case of 'competing' pipelines: Evaluation of five scenarios*, Sydney, October 2000.

National Economic Research Associates, *International comparison of utilities' regulated post tax rates of return in: North America, the UK, and Australia*, Sydney, March 2001.

National Economic Research Associates, *Natural gas pipeline access regulation*, Sydney, May 2001.

National Economic Research Associates, *Foundation contracts and 'greenfields' gas pipeline developments: Experience from the United States and other jurisdictions*, Sydney, March 2002.

Office of the Regulator General, *2003 Review of Gas Access Arrangements, Consultation Paper No 1*, May 2001.

Attachment 4

ACCC/NCC

Regional development of natural gas transmission pipelines

A guide for regional areas considering alternatives for progressing the supply of natural gas

October 2002

Contents

Attachments

Summary

This Australian Competition and Consumer Commission (ACCC) and National Competition Council (NCC) joint publication provides a general overview of key (economic) regulatory considerations involved in assessing new natural gas transmission pipeline projects. This guideline consolidates into one document a summary of the various regulatory agencies, their roles and the likely decision steps involved in assessing options for securing natural gas transmission pipeline supplies.

Regulation is not automatic in the case of gas pipeline infrastructure and indeed some pipelines are not regulated at all. To determine whether a prospective pipeline falls within the regulatory framework a number of tests must be satisfied. However, in some cases where the tests are not satisfied, a pipeline may be volunteered to be regulated anyway. In such a situation the proponent of a new pipeline proposal may consider that regulation provides an increased level of certainty in relation to the treatment of a range of investment critical factors associated with such projects.

The issues facing a pipeline project to a number of rural communities—given the greater distances and reduced population densities—may be substantially different to that of an urban development. Depending on the project-specific issues the commercial viability of such proposals will perhaps be marginal at best, regardless of whether or not it is regulated. This decision, however, is ultimately dependant on the commercial judgment of the parties involved, taking into account its efficient scale and viability.

Quite clearly, uneconomic projects are unlikely to proceed. However, where a project may be considered marginal only in the near term, the regulatory framework provides some flexibility to facilitate what is otherwise a viable proposition. Accordingly, the responsibility rests with prospective pipeline developers to tailor the optimal pipeline configuration and, if regulated, access regime that best meets the specific requirements of a particular proposal.

This guideline will assist those parties seeking to develop natural gas transmission pipelines in their regions by:

- setting out the options—both regulated and unregulated—for progressing natural gas pipelines
- clarifying the circumstances under which a natural gas transmission pipeline is likely to be regulated
- identifying what the regulatory alternatives are for developing new natural gas transmission pipelines
- addressing a number of commonly asked questions and issues faced by regional areas interested in extending natural gas supplies.

A more detailed discussion of the technical issues associated with the regulatory and legislative framework is provided in the latter part of this guide, along with a list of relevant contacts.

While this publication explores issues unique to pipeline infrastructure projects to rural communities, it is by no means definitive. Each proposal will require specific consideration that takes account of its unique characteristics. Therefore, early consultation by project proponents with the relevant regulatory agencies is encouraged.

1. Introduction

This document has been produced in response to the increasing interest of local government authorities in projects for the supply of natural gas to regional communities.

Natural gas is an important input to many Australian businesses and offers an economic alternative to electricity for household heating. The potential economic and social benefits of natural gas have prompted a number of local government authorities and other interested parties in regional Australia to encourage and facilitate the development of gas transmission and distribution pipelines to supply natural gas to some regional areas. The promotion and development of new pipelines may be carried out in a number of ways—and in some cases there may be regulatory implications.

The Australian Competition and Consumer Commission (ACCC) and the National Competition Council (NCC) recognise the need for local governments and interested parties to consider whether a prospective pipeline development is likely to be subject to the regulatory requirements under either the *National Third Party Access Code for Natural Gas Pipeline Systems* (the code)[1] or Part IIIA of the *Trade Practices Act 1974*. A description of the ACCC and NCC roles can be found in section 6 of this document.

This guideline sets out the range of possibilities that may apply to a proposed pipeline project from a regulatory perspective. As every project has unique characteristics that require specific consideration, it provides only a general overview to help interested parties identify the key issues and decision points regarding regulatory issues.

Prospective investors and regional councils are encouraged to consult with the ACCC and NCC at an early stage to discuss any new pipeline developments and identify whether there may be regulatory implications. Contact details for both agencies are at attachment 1 of this document.

When are pipelines regulated?

It is widely accepted that vigorous and effective competition normally provides the best means of promoting economic efficiency, a competitive economy and the welfare of consumers. In some markets, however, competition may not be possible. This has often been the case in some segments of the gas industry. Transmission and distribution pipelines often face limited direct competition because of significant economies of scale and high barriers to entry. That is, they exhibit natural monopoly characteristics. In recognition of the natural monopoly characteristics of some gas pipelines, regulation has been introduced to ensure that pipeline owners provide access to their facilities on reasonable terms and conditions.

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[1] Copies of the *National Third Party Access Code for natural gas pipeline systems* (the code), which is schedule 2 to the *Gas Pipelines Access (South Australia) Act 1997*, can be obtained from <http://www.coderegistrar.sa.gov.au>.

However, note that in the case of gas infrastructure, regulation is not automatic, because, in some cases regulation may not be necessary to ensure the effective functioning and development of natural gas markets. A number of tests must be satisfied before a prospective pipeline falls within the regulatory framework. It is the NCC's responsibility to apply these tests and make recommendations to the relevant minister in response to applications for coverage (regulation) of gas pipelines under the code and declaration of infrastructure services under Part IIIA of the Trade Practices Act.

Also note that although a pipeline may be initially regulated, interested parties have the opportunity to submit an application to the NCC to assess whether regulation should continue. Section 1.9 of the code sets out the four criteria that form the basis of this assessment. Where one or more criteria are not met the NCC will make a recommendation that coverage (regulation) should be revoked. This will then be conveyed to the relevant minister who will make a decision. More detail on this process and the number of approvals granted is provided in section 8 'Unregulated pipelines'.

Once the NCC has determined that a pipeline be covered, the transmission pipeline owner or service provider must submit an access arrangement to the ACCC for assessment.[2] An access arrangement establishes the terms and conditions of access, including price, under which third parties may purchase access or capacity on the pipeline.[3] The ACCC's role includes assessing the implications of the regulatory decision-making process on investment in both the regulated sector and downstream markets. If regulated tariffs are set too high it may stimulate investment in regulated services but at a cost to downstream investment. The reverse applies if regulated tariffs are set too low. Note that terms freely negotiated by parties that are outside those in an access arrangement are not affected by the regulatory process (other than exclusivity provisions).

The ACCC's regulatory role is limited to natural gas transmission pipelines and does not include liquefied petroleum gas (LPG). Any queries regarding this document or other natural gas related queries should be addressed to the ACCC's e-mail address: <gas@accc.gov.au>.

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[2] Gas distribution pipelines are regulated by the relevant regulatory bodies in each state (with the exception of NT).

[3] The ACCC does not regulate the commodity price of the natural gas transported—this is commercially negotiated with the upstream producers.

2. What are the options?

The diagram in flow chart 1 (next page) broadly depicts the options available when considering how to progress the supply of a natural gas pipeline. Essentially there are three possibilities when considering a greenfields transmission pipeline project:

(i) the pipeline becomes 'covered' via a competitive tender or the voluntary submission of an access arrangement under the code, or

(ii) an access undertaking in relation to the pipeline is submitted by the service provider under Part IIIA of the Trade Practices Act, or

(iii) the pipeline is unregulated, i.e. development outside the regulatory framework. The pipeline operator, on the basis of its own commercial assessment, does not seek coverage of the proposed pipeline under the code or submit an access undertaking under Part IIIA.

Some service providers (that is owners or operators of a pipeline) may perceive benefits in securing certainty about the application of the regulatory framework to their particular assets at the outset. The ACCC released its *Draft greenfields guideline* to assist prospective transmission service providers to understand the regulatory options applying to new gas transmission pipelines in greater detail.[4]

Accordingly, the ACCC's regulatory role is limited to the regulation of natural gas transmission pipelines that either:

- meet the regulatory tests and are covered under the code (or possibly the criteria for declaration under Part IIIA of the Trade Practices Act), or
- are volunteered by the pipeline owner/operator for regulation.

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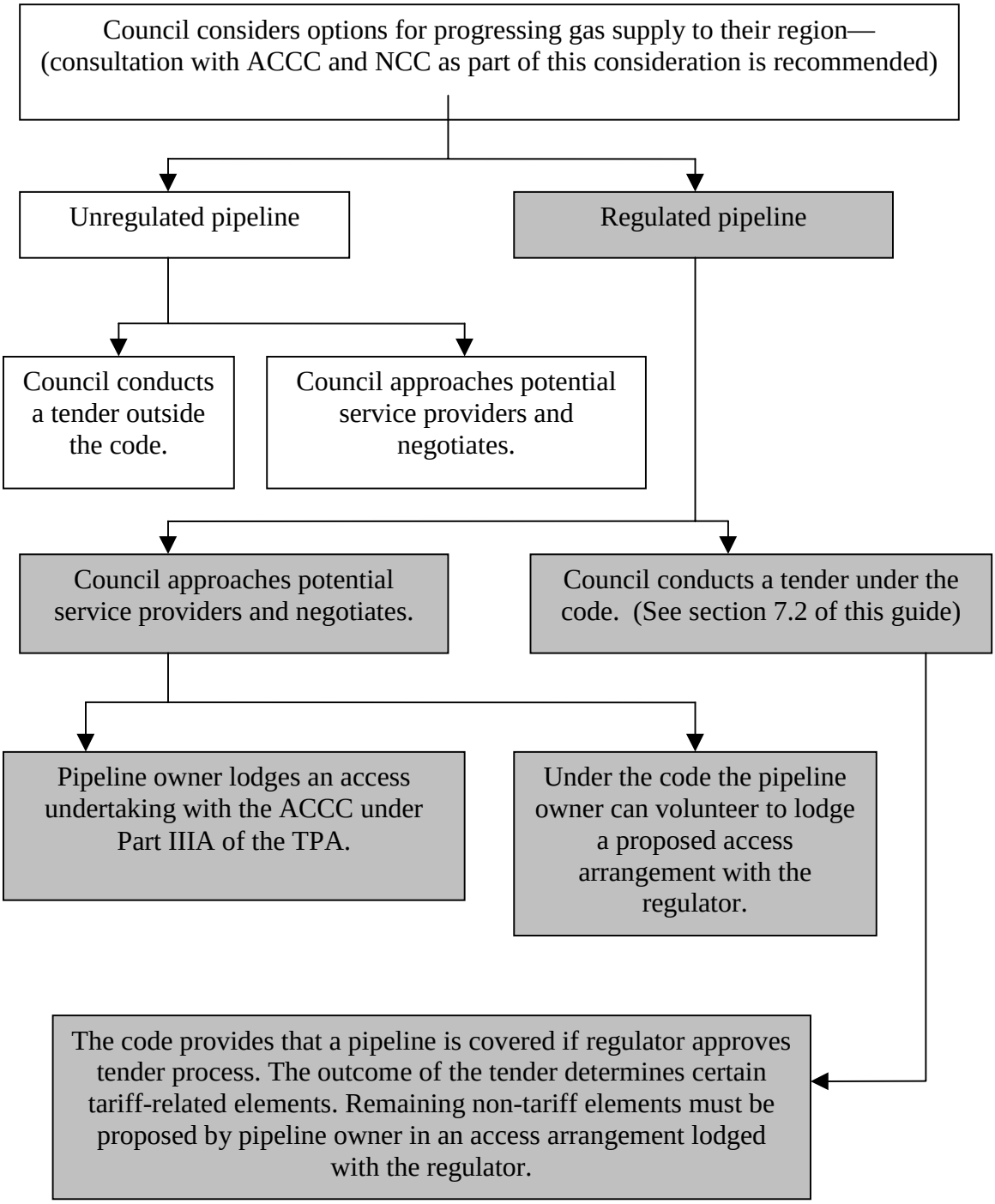
[4] ACCC, *Draft greenfields guideline for natural gas transmission pipelines—a guide to the access regulation framework for new natural gas transmission pipeline developments in Australia,* July 2002. Copies of the guideline and related consultancies are available from the ACCC's website at <www.accc.gov.au>.

Flow chart 1. Options for progressing gas supply



3. The regulatory alternatives for developing new natural gas transmission pipelines

As noted in flow chart 1, if a project proponent takes the 'regulated pipeline' option there are two regulatory alternatives for pursuing a greenfields development project. Whether to conduct a tender or pursue a sole source option is likely to depend on several factors. These are not limited to but include the level of interest among prospective pipeline developers and the assessed benefits of utilising competitive tension to determine the optimal pipeline configuration and terms and conditions on which the transmission services will be provided. These can be briefly summarised as follows.

- **Option 1. A competitive tender in accordance with the code**. The competitive tendering process, if approved by the regulator, means that the transmission pipeline is automatically covered by the code. After the tender process is completed the successful tenderer is required to submit an arrangement to the regulator that sets out tariffs (that have resulted from the tender) and proposes the terms and conditions on which third parties may seek access to the services of the pipeline.

  Section 7.2 of this document provides a more detailed explanation and includes a flow chart illustration of the competitive tender process.

- **Option 2. Development outside the competitive tendering framework, but with an access arrangement or access undertaking**. The council or pipeline proponent develops the greenfields project outside the regulatory framework. The pipeline operator, on the basis of its own commercial assessment, can then:

  (i) seek coverage of the new transmission pipeline under the code by voluntarily extending or submitting an access arrangement under the code, or

  (ii) submit an access undertaking under Part IIIA of the Trade Practices Act.

4. Commonly asked questions

4.1 What is an access regime and what is its purpose?

An access regime is a legal regime for the regulation of access to certain infrastructure services by third parties. An access regime will generally provide:

- a right for third parties to negotiate fair commercial terms for access to the services provided by the infrastructure subject to the regime, and

- a process for the determination of the terms and conditions of access—this process will usually place an emphasis on commercial negotiation by the parties but provide for arbitration in the event that negotiations fail.

The rationale for access regulation is that in some markets the introduction of effective competition requires access to facilities which exhibit natural monopoly characteristics. That is, a single facility can service at less cost than two or more facilities. For example, effective competition in natural gas exploration, production and processing and natural gas sales requires access to gas pipelines.

This may give substantial market power to infrastructure owners. Without an effective access regime this market power can be exploited by the infrastructure owner in upstream or downstream markets[5] to the detriment of consumers by:

- charging monopolistic prices to businesses using the infrastructure, or

- offering other terms of access to its affiliates at the expense of independent competitors.

Where the infrastructure owner is vertically integrated into upstream or downstream markets it may even deny access to independent competitors. Thus, the exploitation of market power by an infrastructure owner will damage competition in those upstream or downstream markets in which access to the infrastructure is essential for competition. Examples of access regimes include both:

- Part IIIA of the Trade Practices Act which establishes a national access regime for access to certain infrastructure services of national significance, such as the services provided by electricity wires, gas pipelines and rail networks, on reasonable terms and conditions, and

[5] Upstream markets refers to markets involved in exploration and production of gas. Downstream markets refers those industries that use the gas that has been transported on the pipeline.

- the code and its supporting state and territory legislation which is a state and territory based national access regime for natural gas pipeline systems. The stated objective of the code is to establish a framework for third party access to gas pipelines that:
  - facilitates the development and operation of a national market for natural gas
  - prevents abuse of monopoly power
  - promotes a competitive market for natural gas in which customers may choose suppliers, including producers, retailers and traders
  - provides rights of access to natural gas pipelines on conditions that are fair and reasonable for both service providers and users, and
  - provides for resolution of disputes.

4.2 What is the difference between a transmission and a distribution pipeline?

When the code was first introduced in 1997 all existing pipelines were classified as either transmission or distribution. A list of these can be found in schedule A of the code.

However, pipelines built after this date have to be classified in accordance with the process outlined in the Gas Pipeline Access Law (GPAL). This process involves either the service provider, ACCC, NCC or state regulator lodging an application with the Code Registrar. This is then forwarded to the state minister, in the case of a distribution pipeline, or the Commonwealth minister, in the case of a transmission pipeline, for approval.

In this assessment process two aspects of a pipeline are considered, namely its function and its characteristics.

The function of a transmission pipeline is to transport natural gas to a region, whereas a distribution pipeline reticulates natural gas within that region. In terms of a pipeline's characteristics, consideration is given to its diameter, the pressure at which it is designed to operate, the number of points at which gas can be fed into it, the size of the area it is to serve or be served by it and, lastly, its linear or dendritic configuration.

4.3 What is the difference between the expansion and extension of an existing pipeline, and a new pipeline?

The expansion of a pipeline and the extension of a pipeline are separate matters and should not be confused.

- An expansion is an increase in the volume of gas a pipeline is able to carry. This can be achieved in several ways (e.g. compression, looping).

- An extension, however, is an additional length of pipeline joined to a currently regulated pipeline. As outlined below, the additional length of pipeline could be classified as either an extension of the existing network or a new pipeline.

In terms of the regulatory impact on a proposed pipeline project:

- an extension or expansion would be required to operate under the terms and conditions already set out in the network's access arrangement. This access arrangement will include a clear statement in the 'extensions and expansions policy' section as to how any significant new investment in the network will be treated. For example, it will explain whether the users of the new investment will be required to pay a tariff or a surcharge.

- In comparison, a new pipeline, if regulated, will have its own access arrangement and tariffs.

4.4 What level of returns would be allowed under the regulatory framework?

The natural gas regulatory framework requires the regulator, in making its determinations, to consider a number of objectives. These include giving a service provider the opportunity to earn revenue that recovers the costs of delivering the service over the expected life of the assets used in delivering that service, to replicate the outcome of a competitive market, to set tariffs that are efficient in level and structure, and to not distort the investment decisions in pipeline transportation systems or in upstream and downstream industries.

The evidence to date is that regulatory considerations have provided generous benchmark returns that provide clear incentives for a service provider to achieve efficiencies, grow demand for its services and outperform the benchmarked return determined for the next regulatory period.

Recent ACCC decisions relating to the gas industry have established forward looking returns on equity of around 12.68 per cent per annum. This compares favourably with returns allowed by overseas regulators and domestic stock market returns. For example, domestic stock market returns at the end of September 2002 were 4.8 per cent per annum over the past five years and 11.2 per cent per annum over the last 10 years.[6] Similarly the returns to the end of September 2002 for selected pooled funds were 2.2 per cent per annum over three years and 4.3 per cent per annum over five years.[7] However, it is important to note that care should be taken in using average market return figures as they can be very volatile.

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[6] All Ordinaries Accumulation Index: 5 and 10 year moving average September 2002.

[7] Mercer Investment Consulting Pooled Fund Survey for period ended 30 September 2002. See <askmercer.com.au>.

4.5 What happens when a tender conducted under the code does not receive any conforming bids?

This is a real risk with running a tender—whether or not it is conducted under the code—and has in fact been the experience of a number of councils in recent times. A conforming tender is one that meets the minimum selection criteria requirements. However, it may be that the tender attracts expressions of interest (and not conforming bids) from potential investors. These would not meet the minimum requirements of the tender rules outlined in the tender documentation, and should this be the case the tender process would finish at this point. Councils may then wish to consider option 2 (of section 3)—i.e. directly approach and negotiate with the parties that have lodged expressions of interest.

4.6 How long can an access arrangement last?

The majority of access arrangements for established pipelines have typically run for five years. But the period may be of any length, subject to the code requirement that if it is greater than five years, then the regulator is required to consider review mechanisms.[8]

A tender under the code is slightly different. In this case the code allows the regulator to consider periods of up to 15 years.[9]

A longer initial access arrangement period may also assist in providing increased regulatory certainty to the investors in new pipelines.

4.7 Will two separate tenders need to be conducted when both transmission and distribution pipeline is required to service an area?

No. It is possible to conduct one tender for the two pipelines. In the past the ACCC has demonstrated its willingness to work with state regulators to streamline the regulatory approval process and reduce the potential financial costs of conducting a tender.

In 2001 the councils of the Loddon Murray region in Victoria conducted a competitive tender under the code. The ACCC worked with the Victorian Essential Services Commission (ESC, previously the Victorian Office of the Regulator General) in assessing and subsequently approving the councils' tender approval request (TAR) to conduct the one tender for the supply of reticulated gas to the region via a transmission

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[8] Refer code s. 3.18.

[9] Refer code s. 3.33(d).

and distribution pipeline. In this case the ACCC and ESC recognised that given the small size of both the project and potential market, requiring two separate tenders to be conducted would potentially work against the tender attracting the number of quality bids to ensure sufficient competitive forces in the tender.

4.8 Can the outcome of a tender be determined on the basis of a 'bundled' distribution and transmission tariff?

No. The objective of unbundled tariffs is to increase transparency in the outcome (pricing) for users of the pipeline's services and this could not be achieved by a bundled tariff. The successful bidder is also required to submit an access arrangement to the respective regulators at the conclusion of the process.

However, in the case of the Loddon Murray tender the councils' TAR proposed that the successful bid be selected based on the 'average combined' transmission and distribution reference and non-reference tariffs delivered over the initial access arrangement period. While approval for this outcome would not normally be considered by regulators in larger projects, in this particular case it was considered both prudent and sensible to run one process and select the winning tender on the basis proposed, subject to tenderers specifying separate reference tariffs for the transmission and distribution components.

4.9 Do we need to employ consultants for a competitive tender process?

Conducting economic feasibility studies, provision of engineering, legal and financial advice, and the conduct and evaluation of an actual tender process itself are some of the specialist areas in which regional councils may require external input to progress a competitive tender process.

In assessing the relevant regulatory considerations to determine the best way to progress securing the supply of natural gas, regional councils are encouraged to engage in early consultation with the NCC, ACCC and relevant state regulators. The objective being to discuss the relevant issues, regional plans and options that are available to progress new pipeline developments and, importantly, whether the regulatory framework need apply at all.

5. The regulatory framework

A basic understanding of the framework for the regulation of access to services provided by infrastructure facilities is necessary to assess the relevant options. This section sets out a brief summary of the regulatory framework for access to gas transmission pipelines.

5.1. Part IIIA of the Trade Practices Act

Part IIIA of the Trade Practices Act establishes a national umbrella framework for the regulation of access to the services provided by infrastructure facilities, such as gas pipelines. In essence, Part IIIA covers nationally significant infrastructure services where:

- development of competitive infrastructure would be contrary to the interests of the community as a whole because the infrastructure has natural monopoly characteristics, and

- access is necessary to promote competition in an upstream or downstream market—that is, access regulation would address structural impediments to competition in a market that relies on the infrastructure service as an input.

Part IIIA establishes three options for a party to seek access to an infrastructure service:

- through declaration

- by using an existing effective state/ territory access regime, or

- under terms and conditions set out in a voluntary undertaking approved by the ACCC.

Declaration

Under the **declaration** pathway, a business wanting access to a particular infrastructure service applies to the NCC to have the service 'declared'. The NCC considers the application before forwarding a recommendation to the relevant Commonwealth, state or territory minister for a decision. For a facility to be declared it must satisfy the declaration criteria specified in Part IIIA of the Trade Practices Act. If a facility is declared, the business seeking access has a right to negotiate the terms and conditions of access with the facility owner. If negotiations fail, declaration also gives the business seeking access the right to have access terms and conditions determined by arbitration by the ACCC.

Effective access regimes

A facility cannot be declared if it is already the subject of an **effective state or territory access regime**. The NCC must determine whether an effective access regime is in place when considering an application to declare a service. For a state or territory regime to be assessed as an effective access regime, it must satisfy the criteria for effective access regimes set out in clause clause 6 of the *Competition Principles Agreement*.

The question of effectiveness can be pre-determined, through a process called 'certification'. A state or territory government may apply to the NCC for a recommendation on the effectiveness of the regime. The NCC considers the application before forwarding a recommendation to the relevant Commonwealth minister, who then decides whether or not to certify the regime as effective. Once a state or territory regime is certified as effective, access to the designated service is exclusively governed by that regime and the declaration provisions of Part IIIA are ruled out.

Access undertakings

Part IIIA allows infrastructure providers to submit a **voluntary access undertaking** to the ACCC for approval specifying the terms and conditions on which access will be made available to third parties. An undertaking may be submitted in relation to existing or proposed infrastructure.

Acceptance of an undertaking by the ACCC provides an equivalent outcome to certification—access is exclusively regulated by the terms and conditions set out in the undertaking and services covered by the undertaking are immune from declaration.

5.2. The National Third Party Access Code for Natural Gas Pipeline Systems (the code)

The code establishes a national access regime for natural gas pipelines. It sets out the rights and obligations of service providers, pipeline users and access seekers. It includes coverage rules, the operation and content of access arrangements, ring fencing arrangements, information requirements, dispute resolution and pricing principles. Under the code the ACCC is responsible for the regulation of all 'covered' transmission pipelines in Australia with the exception of Western Australia.[10]

Once a pipeline is covered it is subject to the principles set out in the code. The code requires individual transmission pipeline operators to submit access arrangements to the ACCC for approval, except in Western Australia.

[10] The Office of Gas Access Regulation (OffGAR) is the responsible regulator for transmission and distribution of natural gas pipelines in Western Australia.

The code is a state and territory based access regime. It gains force from complementary laws adopted by all states and territories, except Western Australia, which has a separate regime based on the code.

As at April 2002 the respective access regimes established by the code and its supporting legislation have been certified effective in all jurisdictions except Queensland (in relation to which a decision is pending) and Tasmania. Accordingly, gas pipelines covered by the code cannot be declared under Part IIIA of the Trade Practices Act.

Declaration remains an avenue for seeking access to gas pipelines that are:

- not covered by the code in South Australia, Western Australia, New South Wales, Victoria, the ACT and NT, and

- not the subject of an access undertaking approved by the ACCC.

However, past experience suggests that in these circumstances it is more likely that a business seeking access will make an application to the NCC for the pipeline to be covered by the code.

6. Who are the relevant regulatory bodies?

The National Competition Council

The NCC was established by all Australian governments in November 1995 to act as a policy advisory body to oversee their implementation of National Competition Policy (NCP). Part IIA of the Trade Practices Act sets out the functions of the NCC.

The NCC's role in the regulation of gas transmission and distribution pipelines primarily includes:

- overseeing the implementation by Australian Governments of NCP gas reforms designed to establish national free and fair trade in gas, in part by improving efficiency in gas transportation, through implementation of the code
- making recommendations to the relevant minister on coverage (and the revocation of coverage) of gas pipelines under the code, and
- making recommendations to the Commonwealth minister on certification of the state and territory access regimes established by the code and its supporting state and territory legislation.

The NCC comprises five part time councillors with a variety of backgrounds who are drawn from different parts of Australia. It is supported by a secretariat of approximately 20 staff located in Melbourne.

The Australian Competition and Consumer Commission

Under the code, the Australian Competition and Consumer Commission (ACCC) is the designated regulator for gas transmission pipelines in all states and territories (except WA) and for transmission and distribution pipelines in the Northern Territory. It is responsible for:

- assessing proposed pipeline access arrangements and subsequent amendments
- monitoring and enforcing reference tariffs, ring-fencing, incentive regulation and other access arrangement provisions
- arbitrating access disputes between pipeline service providers and access seekers
- overseeing competitive tendering processes for new transmission pipelines, and
- assessing applications from industry for authorisation of anti-competitive gas supply arrangements.

The ACCC also regulates the industry through the general merger, anti-competitive conduct and consumer protection provisions of the Trade Practices Act.

The Gas Group forms part of the ACCC's Regulatory Affairs Division. The group is based in Canberra and Sydney.

State and territory regulators

The state and territory (except NT) regulators are responsible for the regulation of natural gas distribution networks, technical and licensing standards and retail price and service standards for the distribution and sale of natural gas in their respective jurisdictions.

7. Regulated pipelines

7.1 Coverage under the code

Once a pipeline becomes covered it is subject to the principles set out in the code. It should be noted at this point that there are three ways in which a greenfields or new pipeline may become covered.

1. A pipeline is automatically covered if it is subject to a competitive tendering process that has been approved by the regulator[11].
2. A service provider or prospective service provider can volunteer that a pipeline be subject to the provisions of the code by proposing an access arrangement to the regulator for approval. Following the regulator's approval the pipeline is covered from the date that the access arrangement becomes effective until any specified expiry date (sections 1.20 and 2.3 of the code).
3. Any person may make an application to the NCC requesting that a pipeline be covered (code section 1.3). The NCC subsequently provides a recommendation to the relevant minister, who makes a decision on the matter. The criteria for determining whether a pipeline should be covered is set out in section 1.9 of the code.

Before deciding on a regulatory approach, if any, a prospective service provider has the option to seek a (non-binding) opinion from the NCC on whether a proposed pipeline would meet the criteria for coverage in section 1.9.[12]

Criteria for coverage

Both the NCC and the minister must consider the criteria for coverage set out in Section 1.9 of the code before making a recommendation or decision, respectively, with respect to coverage of a gas pipeline. Section 1.9 of the code provides:

> Subject to sections 1.4(a) and 1.10. the NCC must recommend that the Pipeline be covered (either to the extent described, or to a greater or lesser extent than that described in the application) if the NCC is satisfied of all of the following matters, and cannot recommend that the Pipeline be Covered, to any extent, if the NCC is not satisfied of one or more of the following matters:
>
> (a) that access (or increased access) to services provided by means of the Pipeline would promote competition in at least one market (whether or not in Australia), other than the market for the services provided by means of the Pipeline;
>
> (b) that it would be uneconomic for anyone to develop another Pipeline to provide the services provided by means of the Pipeline;

[11] Refer code section 1.21.

[12] Refer code section 1.22.

(c) that access or increased access to the services provided by means of the Pipeline can be provided without undue risk to human health or safety; and

(d) that access (or increased access) to the services provided by means of the Pipeline would not be contrary to the public interest.

In essence, the coverage criteria limit the coverage of gas pipelines under the code (other than when the pipeline operator voluntarily subjects its pipeline to the code) to circumstances where:

- development of competitive pipelines would be contrary to the interests of the community as a whole because the gas pipeline has natural monopoly characteristics, and

- access is necessary to promote competition in an upstream or downstream market, e.g. the market for natural gas production and/or natural gas sales.

In addition, the coverage criteria require that:

- access be economically feasible and not be allowed to compromise the system integrity of the pipeline, and

- access not be contrary to the public interest; that is, the benefits of coverage should outweigh the costs.

The NCC must recommend coverage of a pipeline if it is 'affirmatively satisfied' that the pipeline meets **all** of the criteria. If the NCC is not satisfied that one or more of the criteria are met it must recommend that the pipeline not be covered.

The criteria in section 1.9 of the code were considered by the Australian Competition Tribunal (the review body for a coverage decision by the minister) in the Eastern Gas Pipeline decision.[13] The NCC has regard to the principles and reasoning established in that decision in its consideration of all coverage applications.

Based on this the NCC adopts the following process for considering the criteria.

1. Define the point-to-point gas transportation services provided by the pipeline.

2. Examine whether it is economic to develop another pipeline to provide the service (criterion (b)). A pipeline is covered only if the development of other pipelines to provide the service would be inefficient. In this sense, coverage is confined to pipelines exhibiting natural monopoly characteristics; that is, when a single pipeline can serve demand for the point-to-point transportation services at less cost than two or more pipelines.

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[13] Re: Application under section 38(1) of the Gas Pipelines Access Law for Review of the Decision by the Minister For Industry, Science and Resources published on 16 October 2000 to cover the Eastern Gas Pipeline pursuant to The Provisions of the National Third Party Access Code for Natural Gas Pipeline Systems and the Gas Pipelines Access Law [2001] ATPR 41,821.

3. If development of another pipeline to provide the service would be uneconomical, then assess whether coverage will improve the conditions or environment for competition in dependent markets (criterion (a)). For example, providing access may promote competition in upstream (gas production) and/or downstream (gas sales) markets. Whether the conditions for competition will be enhanced depends critically on whether the incumbency and technological advantage (derived from the natural monopoly characteristics of the pipeline) confer substantial market power on the pipeline operator in a dependent market. As part of this evaluation, dependent markets need to be identified, as will factors affecting the ability to exercise market power.

   In the Eastern Gas Pipeline decision, the Australian Competition Tribunal examined demand for gas in Sydney, capacity to supply that demand, likely spare capacity, the commercial imperatives facing the operator, the countervailing power of other market participants in dependent markets, and other sources of supply to dependent markets to determine whether the Eastern Gas Pipeline possessed market power.

4. Assess whether access to the service can be provided safely (criterion (c)).

5. Determine whether access would not be contrary to the public interest (criterion (d)). This criterion comes into play if the other criteria are satisfied and permits factors not raised under the other three criteria to be taken into account. For example, whether any benefits of access, such as cheaper prices and more efficient use of resources, are outweighed by regulatory or compliance costs. Other matters of public interest include environmental considerations, regional development and equity.

The NCC is currently preparing a guide to Part IIIA of the Trade Practices Act, which will include a detailed discussion of the criteria for declaration of an infrastructure service under Part IIIA. The declaration criteria are substantively similar to the coverage criteria and, accordingly, the guide will contain a discussion of the NCC's approach to interpreting the criteria for coverage under the code. The guide will be available on the NCC website at <http://www.ncc.gov.au/>.

Flexibility of the code

The ACCC considers that the code has been drafted to accommodate access arrangements for prospective pipelines. The code aims to provide sufficient prescription while incorporating enough flexibility for parties to negotiate contracts within an appropriate framework. It has been designed to facilitate a national access regime which is consistent between state jurisdictions and balances the interests of investors, developers and users.

The ACCC released its *Draft greenfields guideline*[14] in July 2002 to assist prospective investors to understand whether or not pipelines need to be regulated and the flexibility and options within the existing regulatory framework.

7.2 Conducting a competitive tender

The tender process

The code provides that the regulatory framework for a new pipeline may be established through a competitive tender process. Flow chart 2 (next page) outlines the decision process.

Requirements of the council (local government authority)

The first stage of a competitive tender under the code is the consideration of a tender approval request (TAR) submitted by interested parties to the relevant regulator. Section 3.21 to 3.28 of the code describes the process and criteria that must be addressed in such an application.

The primary objective of a TAR is to gain approval from the regulator to conduct a tender process pursuant to the code. This has the effect of determining the tariff related aspects of the proposed pipeline's access arrangement for the initial period (e.g. up to 15 years). If a tender process is carried out according to the guidelines in the code, the regulator is not required to carry out analysis of costs, returns or tariffs for the initial access arrangement period. It is anticipated that the competitive pressure between bidders for the development rights of the proposed pipeline will produce tariffs that achieve the objectives of the code.

Section 3.21 of the code states that any person may apply to the regulator requesting approval to use a tender process to determine reference tariffs and other items relevant to the determination of the reference tariffs. In most cases this 'person' is likely to be the local council/s.

Once a tender has been conducted and the outcomes approved by the regulator in accordance with the final approval request (FAR) process, the winning bidder becomes the pipeliner. Subject to the access arrangement and licensing requirements being met, the reference tariffs and terms and conditions of the winning bid become the reference tariffs and terms and conditions for the new area for the initial regulatory period. Items not determined by the tender process must be included in an access arrangement and submitted to the regulator for scrutiny in accordance with the code.

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[14] ACCC, *Draft greenfields guideline for natural gas transmission pipelines—a guide to the access regulation framework for new natural gas transmission pipeline developments in Australia,* July 2002. Copies of the guideline and related consultancies are available from the ACCC's website at <www.accc.gov.au>.

Requirements of winning bidder

The winning bidder is required to submit an access arrangement (or a revision to an existing access arrangement) to cover the new area within 90 days of the regulator approving the tender outcome. This access arrangement will include tariffs, terms and conditions determined by the tender process as well as those items not determined by the tender process. The arrangement will be subject to full public review before the regulator decides whether or not to approve it.

The winning bidder must also submit an application for a gas licence (or a variation to an existing licence) to the appropriate state or territory body.

Other considerations

The tender process required by the code may not be appropriate in all circumstances.

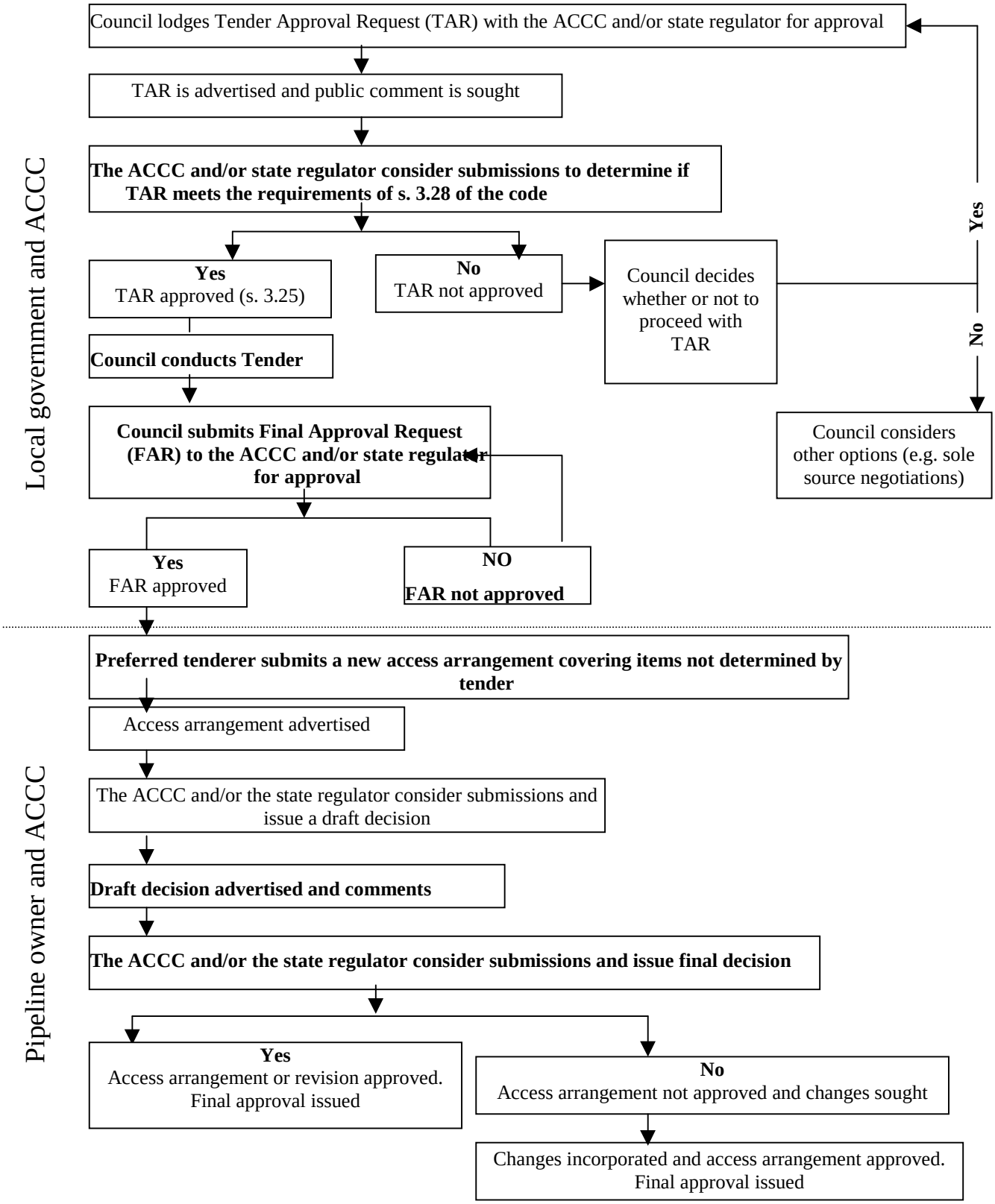
For example, for some pipelines the cost of tendering may outweigh any apparent benefit from testing the market. The ACCC only envisages tendering being used in cases of pipelines to new towns or areas where the forecast demand for gas is of such a scale that competitive bids will be received and the cost of the tender process will be outweighed by the benefits.

Sections 3.28(b) and (c) of the code prohibit the regulator from approving a tender process when it is not 'in the public interest' and when 'the number and character' of tenders received will not ensure a competitive outcome. The code provides no guidance on how these terms should be interpreted. But in considering any request to conduct a tender the ACCC will take into account the general level of interest in the project (of which there may be some indication if expressions of interest have been called for) as well as the number and competitiveness of tenders received in respect of new areas with similar customer numbers, load, and geographic and cost profiles.

The process

The broad process for determining reference tariffs through a tender process can be found in flow chart 2 of this document. The chart sets out the procedure for approval of an access arrangement conducted under the code through a competitive tender process.

Flow chart 2. Competitive tender process



7.3 Submission of a Part IIIA undertaking

Under Part IIIA, service providers can submit access undertakings to the ACCC specifying the terms on which access to infrastructure services, such as gas pipelines, will be made available to third parties.

For further guidance on access undertaking considerations readers are referred to the ACCC guideline, *Access undertakings*.[15]

7.4 Similarities between regimes

While the code may appear more prescriptive than Part IIIA, both are essentially based on the same principles.

Part IIIA was the basis upon which the code was developed. The intention was that an 'access arrangement would be similar in many respects to an undertaking under Part IIIA.'[16] Further, the code was specifically designed to address access to natural gas pipelines. The code is a major component of access regimes that have been certified as 'effective' in a number of jurisdictions.

7.5 Potential for regulatory overlap

As noted above Part IIIA provides for existing access regimes, such as the code, to be recognised as 'effective' by the relevant minister (on recommendation from the NCC). The services covered by jurisdictional gas access regimes that have been recognised as 'effective' under Part IIIA of the Trade Practices Act can not subsequently be declared under Part IIIA.

Part IIIA does not explicitly state that certification of an access regime as 'effective' also excludes the acceptance of an undertaking by the ACCC. However, Part IIIA does require that in assessing undertakings the ACCC will have regard to whether access to the service is already the subject of an access regime. Accordingly, the ACCC will establish whether there is an existing access regime and if so consider whether an undertaking is necessary.[17]

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[15] ACCC, *Access undertakings—a guide to Part IIIA of the Trade Practices Act*, September 1999.

[16] *National Third Party Access Code for Natural Gas Pipeline Systems*, November 1997, p. 1.

[17] ACCC, *Access undertakings—a guide to Part IIIA of the Trade Practices Act*, September 1999, pp. 15, 16.

8. Unregulated pipelines

On the basis of its own commercial judgment a prospective service provider may also elect to build an unregulated pipeline, with or without consultation with regulatory authorities. A typical example of where this would be the case is when the prospective service provider considers that the pipeline would fail to meet at least one of the tests for coverage or declaration under the code or under Part IIIA, respectively.

Prospective service providers are encouraged to consult with the NCC (on whether a proposed pipeline is likely to meet the criteria for coverage in accordance with section 1.9. of the code)[18] and the ACCC, when considering the optimal regulatory approach.

It is important to note that a service provider's election not to provide a voluntary access arrangement or access undertaking does not preclude a third party seeking coverage (under the code) or declaration (under Part IIIA) at some time in the future. As noted earlier, under the code any person may at any time make an application to the NCC requesting that a pipeline be covered. If, based on the NCC recommendation, the relevant minister decides that the pipeline should be covered under the code, the service provider would then be required to submit an access arrangement for the pipeline.

The code—revocation of coverage

Revocation of coverage of a pipeline under the code can be sought (ss 1.24–1.39) by making an application to the NCC. In assessing the application the NCC must be affirmatively satisfied that the pipeline does not meet one or more of the criteria set out in section 1.9 of the code (as detailed above). The NCC's recommendation is subsequently conveyed to the relevant minister, who makes a decision on the matter.

On the commencement of the code, Schedule A listed the pipelines that were automatically to be covered by the code (s. 1.1). Of approximately 47 regulated pipelines in Australia listed in Schedule A and automatically covered by the code, 16 revocations of coverage have been approved in the last four years with one further revocation application pending in NSW. In respect to these pipelines, the application for revocation presented the first opportunity for assessment of the pipeline against the coverage criteria set out in the code.

Some examples of the reasons for the revocation of pipelines include the following.

- Coverage of the Parmelia Pipeline in Western Australia was revoked by the relevant minister in March 2002. The NCC recommended, and the minister agreed, that the pipeline did not satisfy criteria (a), (b) and (d). With regard to criterion (a), the pipeline does not have sufficient market power to hinder competition in the upstream and downstream markets. Furthermore, there is significant unused capacity on the Parmelia Pipeline. Gas consumers in the South West of Western

[18] Refer code section 1.22.

Australia also have a choice of either Perth Basin gas transported via the Parmelia Pipeline or the Dampier to Bunbury pipeline (DBNGP), and Carnarvon Basin gas can also be transported via the Dampier to Bunbury pipeline. The minister also took into consideration the service provider's undertaking to honour current regulated tariffs. With regard to criterion (b), the NCC concluded, and the minister agreed, that the DBNGP may be able to provide the services provided by the Parmelia pipeline. A technical analysis of the ability to economically develop the DBNGP suggested to the NCC, and to the minister, that it is a credible possibility to economically develop the DBNGP to provide the services provided by the Parmelia pipeline.

- Coverage of the Riverland and Mildura pipelines was revoked by the relevant minister in September 2001. The NCC recommended, and the minister agreed, that the pipeline did not meet criteria (a) and (d). The NCC had not received any indication that any retailer had sought, or was likely to seek, access to the pipeline and, equally, no customer had indicated that it had sought access to the pipeline for the purpose of purchasing gas. Furthermore, the NCC was satisfied that there was excess capacity and the pipeline faced incentive to expedite access.

- Coverage of the Palm Valley to Alice Springs pipeline was revoked in July 2000. The NCC was not satisfied that coverage would promote competition in the upstream market because the current producers in the Amadeus Basin (source of gas for the pipeline) were the only likely suppliers of gas into the pipeline and had long term contracts. Furthermore, the NCC was not satisfied that coverage would promote competition in the downstream market for gas sales and electricity generation (gas-fuelled electricity). The pipeline has one customer who was under contract for its current needs until 2008. In the meantime, regulated access would bring no competitive benefit to the customer (and its customers) unless they could grow the market to ship gas above and beyond their current contractual arrangements, which appeared unlikely.

The NCC treats each application for coverage or revocation on its merits. Where pipelines possess similar characteristics, then it could be expected that consistent application of the coverage criteria would result in the same coverage or revocation outcome in respect of each pipeline. However, where there are significant differences between pipelines, a consistent application of the coverage criteria might mean different coverage outcomes.

ATTACHMENT 1

Where to get more information

National bodies

Code Registrar

Copies of the National Third Party Access Code for natural gas pipeline systems (the code), which is schedule 2 to the *Gas Pipelines Access (South Australia) Act 1997*, can be obtained from <http://www.coderegistrar.sa.gov.au> or by phoning (08) 8226 5786.

National Competition Council

The National Competition Council (NCC) was established by all Australian governments in November 1995 to act as a policy advisory body to oversee their implementation of National Competition Policy (NCP). The NCC's role in the regulation of gas transmission pipelines includes:

- overseeing the implementation by all Australian Governments of NCP gas reforms designed to establish national free and fair trade in gas
- making recommendations to the relevant minister on coverage (and the revocation of coverage) of gas pipelines under the Code, and
- making recommendations to the Commonwealth minister on certification of the state and territory access regimes established by the code and its supporting state and territory legislation.

More information on the NCC can be found at <http://www.ncc.gov.au> or by phoning: (03) 9285 7474.

Australian Competition and Consumer Commission

The Australian Competition and Consumer Commission (ACCC) is the designated regulator for gas transmission pipelines in all states and Tterritories (except WA) and for transmission and distribution pipelines in the Northern Territory.

The ACCC website can be found at http://www.accc.gov.au.

Natural gas regulation queries can be directed to e-mail address <gas@accc.gov.au> or by phoning (02) 6243 1111.

State regulators

Queensland

The Queensland Competition Authority (QCA) is an independent statutory authority consisting of members appointed by the Governor in Council. More information on QCA can be found at website <http://www.qca.org.au> or by phoning (07) 3222 0555.

New South Wales

The Independent Pricing and Regulatory Tribunal (IPART) is responsible for the regulation of the water, gas, electricity and public transport industries in New South Wales. More information on IPART can be found at can be found at <http://www.ipart.nsw.gov.au> or by phoning (02) 9290 8400.

ACT

The Independent Competition and Regulatory Commission (ICRC) is a statutory body set up to regulate prices, access and other matters in relation to regulated industries and to investigate competitive neutrality complaints and government-regulated activities. The website can be found at <http://www.icrc.act.gov.au>.

Victoria

The Essential Services Commission (ESC) is the independent economic regulator established by the State Government of Victoria to regulate prescribed essential utility services supplied by the electricity, gas, water, ports, grain handling and rail freight industries.[19] More information on ESC can be found at <http://www.esc.vic.gov.au> or by phoning (03) 96510222.

Tasmania

The Office of the Tasmanian Energy Regulator (OTTER) is responsible for the regulation of the gas and electricity supply industries in Tasmania. More information on OTTER can be found at <http://www.energyregulator.tas.gov.au> or by phoning (03) 6233 6323.

South Australia

The South Australian Independent Pricing & Access Regulator (SAIPAR) was established in May 1998 under the *Gas Pipelines Access (South Australia) Act 1997* to administer the regulatory framework in accordance with the 'national code'. More information can be found at SAIPAR's website <http://www.saipar.sa.gov.au> or by phoning (08) 8226 5788.

Western Australia

The Office of Gas Access Regulation (OffGAR) was established on 23 February 1999 and supports an Independent Gas Access Regulator who is responsible for the regulation of access to both gas transmission and distribution pipelines located within

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[19] In particular refer to the guideline *Gas Industry Guideline No. 2: Provision of Gas to Areas not Serviced by an Existing Distributor* [Issue No. 3] (updated on 31 May 2001).

the boundaries of the state. More information on OFFGAR can be found at <http://www.offgar.wa.gov.au> or by phoning (08) 92131900.

Northern Territory

The ACCC is the designated regulator for natural gas transmission and distribution pipelines in the Northern Territory.

The Utilities Commission of the Northern Territory is the independent industry regulator, established to oversee those industries declared to be regulated industries. More information about the Utilities Commission can be found at <http://www.utilicom.nt.gov.au> or by phoning (08) 8999 4580.

ATTACHMENT 2

Glossary of industry terms

Access arrangement	Arrangement by owner or operator of a covered pipeline setting out the terms and conditions and tariffs on which third parties may seek access to the services of the pipeline. Access arrangements must be approved by the relevant regulator as complying with the requirements of the national code.
Code	National Third Party Access Code for Natural Gas Pipeline Systems. The code is part of the GPAL (Gas Pipeline Access Law) and is set out in Schedule 2 to *the Gas Pipelines Access (South Australia) Act 1997*.
ACCC	Australian Competition and Consumer Commission .
Covered pipeline	Pipeline to which the provisions of the code apply.
FAR	Final Approval Request has the meaning given in section 3.29 of the code.
Fixed principle	An element of the reference tariff policy that can not be changed by the regulator without the agreement of the service provider. It may be any **structural element** but not **market variable element** of the reference tariff policy. The code allows for tender rules and procedures to stipulate that certain tender outcomes will be fixed for a specific period and not subject to change when a service provider submits for a review of an access arrangement.
Fixed period	Period during which the **Fixed Principle** may not be changed. A fixed period may be for part or all of an access arrangement.
GJ	Gigajoule, a unit of measurement for measuring the energy content of natural gas or other energy sources.
GPAL	Gas Pipeline Access Law, which in conjunction with the national code and the Gas Access Acts, sets out provisions of the regime for third party access to the services of gas pipelines. The GPAL is set out in schedules 1 and 2 to the *Gas Pipelines Access (South Australia) Act 1997*.
Market variable element	Means 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. This can include sales or forecast sales, any index used to estimate the general price level, real interest rates, non capital costs and any cost on the nature of capital costs.
MDQ	Maximum daily quantity.

NCC	National Competition Council.
Pipeline	Has the meaning given in the Gas Pipeline Access Law (GPAL).
PJ	Petajoule (equal to 1 000 000 GJ).
Reference tariff	Means a tariff specified in an access arrangement as corresponding to a reference service and which has the operation as described in sections 6.13 and 6.18 of the code.
Ring fencing	Restricting flows of information and personnel within an integrated utility, and between related businesses.
Service provider	In relation to a regulated pipeline or proposed pipeline a service provider is the person or entity that is to be the owner or operator of the whole or any part of the pipeline.
TAR	Tender Approval Request has the meaning given in section 3.21 of the code.
TJ	Terajoule (equal to 1 000 GJ)weighted average cost of capital.
Undertaking	A form of voluntary regulation providing for access to a service. Undertakings are provided for under Part IIIA of the Trade Practices Act and must be approved by the ACCC.
Upstream and downstream markets	In a production chain, upstream markets are markets for the inputs required to produce a good or service; downstream markets are the markets which use that good or service as inputs to produce a more value-added good or service. In the gas supply industry, gas exploration, production and processing are 'upstream' industries and retail supply is 'downstream'.
Vertical integration	Bringing successive stages in production and marketing under the control of one organisation, e.g. combining gas exploration, production, and processing, transmission, distribution and retailing.
WACC	Weighted average cost of capital.