SUBMISSION

Open Access and the Development of the Eastern Gas Pipeline

Productivity Commission
Review of the National Access Regime
Position Paper- March 2001

INTRODUCTION

The Productivity Commission's review of the National Access Regime is of great importance to the Australian economy. The opening up of the access to monopoly infrastructure over the last five years has, in the energy sector at least, lead to significant economic gains.

This submission focuses on what BHP believes are the key issues raised by the Productivity Commission's position paper. BHP has attempted to bring some real world concerns to what we see as a largely theoretical paper. The paper seems to have been developed without regard to history and to have assumed that monopoly infrastructure is somehow quarantined from the rest of the economy. For example, it is assumed that pricing above cost may not impact upstream and downstream market.

The Commission should recognise that monopoly infrastructure is a means to an end and not an end in itself. It exists to link producers with consumers and cannot be looked at in isolation.

1. Industry Specific Codes

The Productivity Commission's proposal that the general obligations of Part IIIA should take precedence over the provisions of industry specific codes if there is any conflict is in our mind poorly considered and should be reversed.

Without exception industry specific codes have been developed by taskforces of industry experts that represent all stakeholders. As a result they are considered documents that deal with the unique access circumstance of each industry. They are by no means perfect but they have been shown to work effectively. Access to existing infrastructure has been achieved in a cost effective manner and, new greenfields infrastructure has and is being developed under them to meet the needs of the economy.

BHP supports APPEA's vision for a national access regime. It is that Part IIIA provides a universal access system applying to all eligible services economy-wide. An industry specific regime which has been certified as effective via the provisions of Part IIIA, in effect, has been found to be consistent with Part IIIA by some measure. Recognising this, the Part IIIA process should cause access to those services to be considered via the processes of the industry specific regime as the appropriate Part IIIA handling process. The industry regime is subsidiary to and consistent with the Part IIIA provisions against which access to any service can be tested. In the case of gas pipelines, a Part IIIA application regarding access would automatically and quickly find its way into the Code forum, obviating 'forum shopping'.

BHP believes that there is no benefit from providing a choice of regulation alternatives, a smorgasbord of different favours and varieties of regulation. Rather, there should be only 2 categories – regulated and unregulated.

If any inconsistency exists between Part IIIA and an industry specific code The industry specific code should take precedence. Part IIIA should be amended to direct coverage of monopoly infrastructure to the relevant code if one exists.

2. Categories of Infrastructure

The Productivity Commission has assumed that "one size fits all" regulation is appropriate for monopoly infrastructure access regulation. BHP submits that a broad-brush approach is not appropriate and it must be acknowledged by the Productivity Commission and regulators that monopoly infrastructure falls into different classes. Established infrastructure and brown field additions are one class while marginal greenfields infrastructure is another class. The benefits and costs to the economy of allowing asset owners to earn returns above cost vary significantly depending on the class of infrastructure.

If returns above cost are allowed for established infrastructure and incremental additions, the result will be sub-optimal economic welfare and growth as the marginal unit of production will not be produced at either end of the value chain. For example; in the gas chain returns to the pipeline owner above cost will cause delivered prices to be higher than they have to be to ensure long term supply. As a result the marginal "widget" will not be manufactured. If the marginal "widget" is not produced the production of the marginal unit of gas will be deferred.

The net result is that the increased dividends that may flow to the monopoly asset owner through pricing service above cost is less than the dividends that would have flowed to the owners of the gas production rights and "widget" manufacturer. Economic growth and overall consumer welfare will have suffered.

BHP is not saying that the owners of existing monopoly assets should, on each day, be capped at a return that is equal to short-run marginal cost or for that matter long run marginal cost. Rather, we believe that asset owners should be given the opportunity and the incentive to earn a return above long run marginal cost in a regulatory period, provided they can outperform reasonable forecasts of throughput and costs.

If it is clear that the development of marginal greenfield monopoly infrastructure would have benefits to the economy as a whole then it may be appropriate, as a matter of principle, to encourage a more flexible approach to cost recovery. For example the developer of the asset may have a number of regulatory periods in which it can earn a return above risk adjusted cost if it outperforms reasonable forecasts.

Within industry specific codes a number of mechanisms exist to allow the developers of greenfield infrastructure the opportunity to manage their capital cost risk. For example under the National Third Party Access Code for Natural Gas Pipeline Systems an asset owner may place a portion of its capital investment in new facilities into a Speculative Investment Fund. The fund is indexed at the new facilities WACC and as demand grows it can be drawn down and added to the asset owner's regulatory asset base.

Regulators have also demonstrated that they are flexible when it comes to the specific needs of greenfield infrastructure. The ACCC, in its decision approving AGL's proposed access arrangement for it's Central West Pipeline agreed to a 10 year initial term and the placement of a significant portion of the projects capital base into a Speculative Investment Fund. In addition as requested by the asset owner, the ACCC approved a usage based tariff rather than a capacity based tariff.

"Access holidays" are not required in order to simulate the development of marginal greenfields projects. As demonstrated above alternative approaches already exist that balance the rights of users and the asset owner. If governments wish to promote the development of infrastructure projects that are not otherwise economic, a more efficient way is to address the principle risk that a project faced ie the market. This could be by means of capital grants (eg Central West received a Commonwealth grant, the South West pipeline received a Victorian government capital grant) rather than protecting these pipelines from third party access. The costs of such a grant are up-front and transparent, whereas the costs of denying third party access are long-term and insidious. In our view this type of "access holiday" plays into the hands of those vested interests wish want to return to the pre-Hilmer days of exclusive franchises and a take-it-or-leave-it approach to doing business with monopoly asset owners.

3. Practical Problems with Depreciated Optimised Replacement Cost Pricing (DORC)

The use of DORC as a means of asset valuation, and hence in setting of target revenue, is subject to some significant practical problems. These problems are sufficiently severe to completely outweigh the alleged theoretical economic benefits of DORC. The practical problems include:

1. Cost
2. Unreliability
3. Susceptibility to gaming

DORC is a High Cost Regime

The concept of DORC is simple: the depreciated cost of a replacement system that has been optimised to provide the same service capability at minimum cost. Achieving this in practice is an expensive, information intensive and time-consuming exercise.

The service provider has a substantial information advantage over the regulator and the users of the service.

The challengers of estimating the capital cost of a major project are well known – every new project requires a capital cost estimate. BHP has had considerable experience with capital cost estimation, with varying degrees of success. A general rule of thumb is that developing a 'project sanction' grade estimate of capital cost will cost between 3% to 5% of the final capital cost. 'Sanction grade' means a capital cost estimate that is a suitable basis for an investment decision. The reliability of this grade of estimate would be ±15% ie the actual capital cost would be unlikely to be outside the range of 85% to 115% of the estimate. Applying this rule of thumb to regulated infrastructure shows the cost of using replacement cost. It has been estimated that there is $50 bn of infrastructure that is subject to access regulation. Estimating the replacement cost of this would cost between $1.5-$2.5 bn. In practice, multiple replacement cost estimates are produced – one by the service provider, one by those that pay for the infrastructure, one by the regulator trying to make sense of the other two estimates …… Taking NSW gas distribution as an example, with an estimated replacement cost of $3bn, a reliable cost estimate would be expected to cost $100-150 m.

This cost would likely to be borne by gas consumers. If it was amortised over 5 years (the term of the access arrangement), it would equate to an annual cost of $20-30m, which is up to 10% of the total target revenue for the network.

In practice, the regulators have only spent a very small fraction of this cost in estimating replacement costs. This has resulted in gross assumptions being made – for example, in all cases that BHP Petroleum has reviewed it has been assumed that the existing system design and layout is the optimised design and layout. The quality of the estimates reflect the money spent in developing the estimates – the rule 'you get what you pay for' applies.

Note that under the Gas Code estimating the replacement cost is a one-off exercise as a component of setting the initial capital base. However, under the Electricity Code the replacement cost could be redetermined at every review, so these costs will be incurred every 5 years or so.

<u>DORC is unreliable</u>

Another problem with DORC is that it is unreliable, in that it cannot be reproduced. Every DORC estimate is different, depending on key assumptions. This unreliability introduces additional risks for the service provider and for the users. If sufficient money is spent (3-5% of total cost) on developing a reliable replacement cost estimate, even that estimate may be in error by ± 15% purely on the basis of different capital cost estimates. Regulated service providers are often valued at multiple of the regulatory asset base (RAB) – typically 1.5 times RAB (reflecting the generous cost of capital allowed by regulators, low-risk growth opportunities etc.). Thus, under a replacement cost regime, the market valuation of a service provider could swing by ± 15% purely on the basis of different capital cost estimates. This additional risk would have to be reflected in a higher cost of capital, further increasing the cost of using a replacement cost regime.

Developing a DORC for an existing network is a purely theoretical exercise. The value calculated for the network depends on which party commissioned the engineering consultant. This is clearly demonstrated by the DORC studies that have been done for AGL's NSW Gas Distribution Network. Since 1996 a number of studies have been done to calculate a DORC for AGL's NSW gas distribution network.

A DORC is calculated from an ORC. The ORC is developed via a process of predicting peak loads on various parts of a network system and then optimising the sizing pipes and compressors to serve that load. The optimal configuration is then valued using unit rates eg; X$/m of pipe, Y$ per valve etc. Different engineering firms may develop vastly different configurations an/or apply different unit rates to the same asset. ORC's can vary substantially. The table below illustrates the ORC for AGL's NSW network as at 1/7/96. The different values represent different engineering firms estimates. The JP Kenny report was commissioned by the regulator IPART and the PPK Kinhill report was commissioned by the owner of the assets AGL

Gas Distribution AGL's NSW Network ORC as at 1 July 1996				
Item	JP Kenny Total $000	PPK Kinhill Total $000	PPK-JPK $000	PPK% JPK
Trunk Mains	170418	150990	-19428	89%
Total Other Mains	1689218	2233795	544577	132%
Total Services	370669	527896	157227	142%
Total Reg & Filter	51413	59092	7679	115%
Total Meters	156309	141819	-14490	91%
SCADA	0	4156	4156	-
Total	2438027	3117748	-679721	128%

This example illustrates the unreliable and subjective nature of replacement cost estimates.

Susceptibility to Gaming

A further major problem with DORC is its susceptibility to gaming. Every element of the calculation is both information intensive, and is open to a wide range of interpretations. As BHP has noted in other submissions, the number of possible DORC valuations is the multiple of the number of valid assumptions by the number of consultants that are willing to be paid to undertake the work. DORC is not a methodology, it is a semi-random number generator.

The following 'Cynic's Rules' illustrate just some of the gaming opportunities.

A Cynic's approach to Replacement Cost valuations*

Rule 1
Always maximise asset values and minimise return on assets to comfort the Regulators.

Rule 2
When re-valuing assets assume the company's main business is pipeline construction so all its overheads can be factored into the costs. Also include these overheads in operating costs.

Rule 3
The present location of the pipelines must be best, otherwise they would not have been located there.

Rule 4
The present configuration of the pipeline system must be best, otherwise they would not have been constructed in the manner they have been.

Rule 5
It is impractical to configure notional systems using new technologies. Never apply a technology which will result in a smaller pipe size.

Rule 6
Ignore all capital contributions made by others.

Rule 7
Be conservative with design inlet and outlet pressures to maximise pipe sizes.

Rule 8
If relevant unit cost data doesn't exist to fairly estimate pipeline replacement costs, scale up from some recent short length jobs or ask a friendly contractor about the unit rates they would like to charge.

Rule 9
Maximise the remaining life of the assets to minimise the extent of depreciation when setting asset values. Then minimise remaining life to bring cash flow forward.

Rule 10
Make sure low depreciation rates are applied for asset valuations and high rates are applied for tax.

Rule 11
Review all construction specifications ahead of the re-valuation to ensure the highest possible standard is adopted.

Rule 12
Include easements and land at current market rates and maximise environmental liabilities. Ignore any revenue received from land sales.

Rule 13
Make sure asset management consultants employed by the regulator are flooded with data and restrict the time available to perform their tasks. In all other circumstances, retain watertight ownership of information.

Rule 14
Engage a big name asset management consultant to validate the valuation to impress the Regulators. Make sure they say they have relevant experience.

**The contribution of James Lomatt, formerly of the National Gas Corporation, NZ to these rules is acknowledged*

Conclusions

There are a number of practical problems in using replacement cost as the basis for valuing regulated assets. These problems are substantial, and they result in higher cost and higher risk. The theoretical efficiency benefits of replacement cost pricing are largely illusionary.

The overriding principle should be simplicity and reliability. In the case of energy infrastructure, this means depreciated actual costs.

4. Pricing Principles

Any general pricing principles that are included in Part IIIA must be balanced and adequately protect the rights of both asset owners and users. They must also provide clear guidance to regulators and arbitrators. The pricing principles proposed by the Productivity Commission maybe conceptually pure and well meaning but are open to significant abuse and manipulation in the real world.

To date the regulators of monopoly infrastructure covered by Part IIIA have adopted a number of flexible pricing approaches that reward the asset owner for outperforming efficiency benchmarks and include risk adjusted capital returns in revenue targets. As appropriate specific circumstances, regulators have incorporated into their approval of asset owner's access proposals:

a) The opportunity for the asset owner to keep gains in excess of the “X” factor
b) Trigger mechanisms that allow access proposals to be revisited within the term if specific events occur
c) Used the CAPM model to calculate the WACC for the asset subject to access. The CAPM model takes account of specific risk premiums

BHP agrees with the Productivity Commission’s view of what access pricing should be trying to do from a policy perspective. The Productivity Commission states:

“From a policy perspective, the issue is one of finding pricing instruments that allow infrastructure owners to cover total costs on an ongoing basis with the smallest impact on efficient use of the services concerned.”

However, we do not believe that the proposed pricing principles will achieve the stated policy objective. Taking the principles one at a time.

Proposed Principle:

- “Generate revenue across a facility’s regulated services as a whole that is at least sufficient to meet the efficient long-run costs of providing access to these services, including a return on investment commensurate with the risks involved”

  The concept that efficient long-run cost should be a revenue floor as opposed to a revenue ceiling or a revenue target is clearly of deep concern to any user of monopoly infrastructure. We fail to see how over compensating asset owners for existing infrastructure can produce any net gain to the economy. In fact quite the opposite occurs. Economic resources will be diverted into infrastructure assets via “gold plating” and other forms of over investment in the knowledge that they are almost certain to earn above normal returns. If above normal returns were not guaranteed these economic resources would have been directed to other more productive uses.

  To date most asset owners regulated under the umbrella of Part IIA have enjoyed regulatory decisions that provide them with a revenue stream well in excess of their actual costs. Regulators have set regulatory asset value well in excess of the DAC of the asset.

  The argument that a normal risk adjusted return should be the floor for greenfield infrastructure is absurd. If a project’s WACC is calculated properly it should take into account the project specific risk. It is perhaps more important that regulators accept that not all WACC’s are the same and that risky projects deserve the opportunity to earn an “appropriate” return. If the argument is that returns are always capped at a normal risk adjusted return then a more appropriate way of encouraging efficient greenfield investment may be to allow the asset owner the opportunity to earn a return above it’s WACC if in a regulatory period it outperforms reasonable forecasts of growth and costs (this mechanism is used in the National Gas Code).

Proposed Principle:

- "Not be so far above costs as to detract significantly from efficient use of services and investment in related markets"

  This principle reinforces the Productivity Commission's concept that the pricing of monopoly infrastructure should be above cost. The only cap being that it does not significantly detract from efficient use of services and investment in related markets. We assume that this means upstream and downstream markets that use the monopoly infrastructure. The concept that one part of a delivery or service chain can earn a return above cost and not impact significantly on related markets is naïve. All non-monopoly markets have vulnerable frontiers where the marginal producer exists. If recoveries in the monopoly section of a supply chain are above cost it is highly likely that the marginal "widget" will not be produced. As a result economic growth and welfare will be less than they would have been had the pricing of the monopoly section of the chain been based upon reasonable costs.

Proposed Principle:

- "Encourage multi-part tariffs and allow price discrimination when it aids efficiency"

  The concept of multi-part tariffs provided they send the correct signals is good. However, a principle that enshrines price discrimination while maybe theoretically acceptable is open to serious abuse by the asset owner and distorts economic decisions in related upstream and downstream markets.

  If price discrimination is accepted as a principle, over time distortions will occur in the economy as projects that cannot pay their own way (fully distributed cost) are developed while other sectors of the economy pay more than they would have. Lost production from these sectors of the economy can never be accurately known.

  Price discrimination is a particular problem where the infrastructure owner has an interest in upstream or downstream markets. In these circumstances, it is likely to mean 'mates rates', damaging competition in related markets.

Proposed Principle:

- "Not allow a vertically integrated access provider to set terms and conditions that discriminate in favour of its downstream operations, unless the cost of providing access to other operators is higher"

  BHP fully endorses the first part of this proposed pricing principle. It is the caveat that is of serious concern. If cost reflective third party access is not allowed it can only ever be the subject of speculation that the cost of providing access to others is higher than the asset owner doing the entire job itself. Only by allowing open access can efficiencies that the incumbent will always assert do not exist be accessed. In addition once monopoly infrastructure is open to access new innovations and more efficient supply chains may develop that were never considered by the incumbent or regulators prior to access being available.

In the real world vertically integrated asset owners would use this principle to destroy any competitive threat. They would always develop a cost allocation approach that demonstrated that the cost of providing access to other operators is higher than if they did the job themselves. Information asymmetry would ensure that regulators and competitors could never disprove the incumbents' assertions.

5. What Pricing Principles Should There Be?

If general pricing principles are to be included in Part IIIA they must be balanced and guide regulators and arbitrators to outcomes that do not distort investment, production or usage decisions for monopoly infrastructure and in associated upstream and downstream markets. To do otherwise would introduce a legislated bias that will lead to suboptimal economic outcomes.

BHP believes that the pricing principles proposed in our initial submission are appropriate for general pricing principles. They are as follows:

1. Pricing should give the opportunity to cover
   - There should be a revenue target with the possibility of recovery of costs or more than the target, dependant in the efforts of the service provider. It should not be set as a 'revenue requirement' or other forms of guaranteed return.
   - The target rate of return should be based on a weighted average cost of capital that reflects how an efficient asset owner would finance the infrastructure
   - The initial regulatory asset base should be set an appropriate level. Within the energy transmission and distribution sector this should be depreciated actual cost
   - The regulatory asset base should only be depreciated once. Depreciation should be based on economic life
   - Allowable operating costs should be only those costs than an efficient and best practice operator would incur

2. All users must be subject to the same price for the same service

3. Users should only have to pay a price that reflects the costs of the assets they actually use. Users should not pay for assets that they do not use.

4. Prices should be determined on a fully distributed cost basis, on the basis that it is equitable and simple when compared to the alternatives.

5. Any form of impost to fund a community service obligation must be completely transparent

If it is determined that marginal stand-alone greenfield infrastructure investment that provides a service where no service was previously available is a special case, then separate pricing principles should be developed for this type of infrastructure. In general marginal greenfield specific pricing principles could explicitly provide for more flexible cost recovery approaches provided that the project as a whole enhances economic welfare and growth. In the interests of equity and competitive neutrality any flexibility should be ring fenced to the specific greenfield asset and not be spread across an asset owners entire asset base.

PART 2

BHP EXPERT PAPERS

Paper 1	**Review of National Access Regime** **Prepared by Peter Fitzgerald**
Paper 2	**Natural Gas Pipeline Access Regulation** **Prepared by Jeff Makholm and Michael Quinn of NERA**
Paper 3	**Asset Valuation and Regulation of Energy Infrastructure Tariffs in Australia:** **The Use and Deficienceis of DORC** Prepared by Professor David Johnstone of University of Wollongong

REVIEW OF

NATIONAL ACCESS REGIME

Prepared for BHP Petroleum

Peter Fitzgerald

May 22nd 2001

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1. INTRODUCTION & EXECUTIVE SUMMARY

We have prepared this document for BHP Petroleum in response to the Position Paper issued by the Productivity Commission in relation to its review of the National Access Regime – Part IIIA of the Trade Practices Act.

This paper will focus on issues relating to (i) regulation of monopoly access pricing and (ii) infrastructure user rights.

They will be addressed from the perspective of the energy industry – including gas and electricity access arrangements.

1.1 Comment on Productivity Commission's Terms of Reference

The Productivity Commission has received an extensive Terms of Reference to review clause 6 of the Competition Principles Agreement (CPA) and Part IIIA of the Trade Practices Act.

The terms of reference invite the Productivity Commission to undertake, inter alia, a cost-benefit review of the matters. Although this sounds logical and even comprehensive it calls for some comment:

- The Review is one that was "scheduled" to occur (it now being five years since the signing of the CPA). It does not arise as a policy initiative from a sense of failure or "real-world" concern. It is unrelated for example to the market and regulatory failures coming out of California; it is also unrelated to any real concern of the regime having failed in any substantial sense.

- The five year history of Part IIIA is best described as having two preparatory phases: the first between 1995-1998 where the major events were efforts to develop industry-specific access codes in gas and electricity, which were then put to use in the second phase, during 1998-1999, where prices for access to gas and electricity transmission and distribution systems were actually set. In this context the third phase involving an actual history of the practical application of these regimes is less than 2-3 years old.

- The Review has adopted a theoretical economic efficiency perspective of "access regulation", instead of adopting a practical viewpoint of access where it is analysed as a necessary and central feature of the much larger phenomenon involving national competition and energy reforms. Effective and cost-reflective access, for example, is a central prerequisite to the task of creating of an open, non-discriminatory and competitive energy market for consumers of all profiles. At this point in time (May 2001) 95 percent of Australian energy consumers are still waiting for contestability (with various deadlines falling due in 2001-

2002). In this sense the Review is both misdirected in scope and premature in timing.

- Similarly the Review does not explicitly seek to revisit the world of energy markets and infrastructure arrangements pre-1995. Instead it takes as a given that energy reforms have been undertaken, and seems to assume that efforts to develop workable and competitive energy markets are either on track or complete. This latter point is almost certainly a premature assumption.

- Since the Review does not start with an assessment of the state of energy reform (including its successes, failures and requirements forward) the Productivity Commission has not sought to determine the importance of the access regimes to the overall reforms. In contrast the Business Council of Australia last year commissioned a report on the state of energy reforms and what was needed to be done to complete the task. The report (undertaken by Port Jackson Partners (PJP) and discussed in more detail below in para 1.2) concluded that there were a number of areas requiring attention of which access regimes generally were not included (although it did note the specific issues with investment incentives for electricity interconnectors). The PJP report assumed, as one would expect, that there would be a continuation of existing regulatory arrangements for access and did not identify the "access regime" as a problem area in need of overhaul.

1.2 Comment on the state of energy reform

The Review should note that the Hilmer-inspired national access regime, and its offspring, the National Gas Access Code and the National Electricity Codes, have played a central role in gas and electricity reforms over the past 5-7 years.

In that time virtually every energy utility in the country has been restructured, many renamed, and usually transferred from public to private ownership. Restructures have involved tens of billions of dollars of transactions.

The introduction of access regimes in gas and electricity have been undertaken with significant levels of participation by owners, operators, retailers and consumers. Given that reforms have involved substantial changes to the property rights (and value chain distribution), the process has not surprisingly been intense but with a general sense of consensus about the nature of the preferred outcomes for access; sustainable pricing and sustainable investment, with fair and non-discriminatory access.

However it should not be glossed over that the higher level objective of energy and competition reforms is to develop a fully competitive market for consumers. This objective has not yet been met and it is therefore not yet appropriate to "declare success" on the overall reform package.

The report of Port Jackson Partners (March 2000) for the Business Council of Australia was entitled "Australia's Energy Reform – An Incomplete Journey." It identified eight problems, only one of which related to access.

The "assessed problems" were:

- The size and mix of electricity generation capacity in South Australia and the entities created in NSW and Queensland are currently unable to sustain competitive outcomes
- Insufficient electricity interconnection links have been built
- The East Coast gas market currently has limited supply options and other impediments to competitive trading
- Governments appear to have extracted significant revenue from the electricity and gas industries during the reform process
- Some economic signals have been blurred, particularly in relation to electricity transmission and distribution pricing
- The regulatory arrangements are cumbersome and provide poor economic signals
- The move to full retail contestability

It should be noted that since the release of this report little has changed, except that a new set of California-related concerns have arisen. Access regimes are therefore important but it should not be assumed by the Productivity Commission that modifications to the rules and operation of access arrangements are mission-critical at this point of time, (with the possible exception of those related to regulation of investments in electricity interconnectors).

1.3 Summary of views

Although the Productivity Commission has commendably proceeded towards a set of possible reform proposals and has given itself the task of further examining the practical aspects of them, the Review underestimates the importance of access to the wider objective of energy reform. As a result the package lacks balance, particularly where it seeks to wind-back the scope of regulatory protection for those seeking access. Specifically:

- The proposal to ensure that access seekers are provided with more information (Proposal 6.3) is to be supported as being both fair and efficient from a regulatory and commercial perspective
- The proposal to allow pricing that is discriminatory and/or above the cost of providing the service (Proposal 8.1) underestimates the

problems with monopoly pricing practices at both a practical and policy perspective

- The proposal to depart from the recently developed building-block approach to setting revenue requirements and reference tariffs (Proposal 8.2) is also premature and unwise and is likely to create a new source of regulatory and commercial uncertainty and disputation

- The proposals to create better accountability, transparency and clearer rules for appeals (Proposals 9.1 to 9.7) are all to be supported.

2. REGULATION OF MONOPOLY ACCESS PRICING

The Position Paper has expressed concerns that regulation of monopoly access pricing may act as a disincentive to investment and to inefficient pricing and usage of the infrastructure.

These concerns are subject to challenge on a number of grounds, as are the set of proposals which seek to ease the role and extent of access regulation:

- The concerns expressed are largely based around economic theory and are not based on an assessment of practical outcomes identified by participants

- The major ‘real-world’ concerns have not been low returns to asset owners nor with low investment (except electricity interconnectors). Quite the opposite has been true, it has been an era of substantial gains and investments by infrastructure owners (particularly the regulated distribution businesses)

- The major problem that has been underestimated by the Productivity Commission in the Position Paper is the problem of monopoly pricing and strategic behaviour that existed pre-Hilmer and which is still being unwound. In particular the Productivity Commission underestimates the wider cost to energy reform and to the national economy of such issues

- Further the proposals identified, particularly those allowing discriminatory pricing and pricing that exceeds the cost of providing the service (Proposal 8.1) underestimate the problems with monopoly pricing practices at both a practical and policy perspective

2.1 Position Paper underestimates the historic problems with monopoly infrastructure

It is our contention that in framing its reform proposals in relation to the regulation of monopoly access pricing, the Productivity Commission has been too reliant on economic “efficiency” theories and has paid too little attention to the actual experience of the energy ‘market’ pre-Hilmer and the emerging (albeit early) history with the application of access regimes to infrastructure assets of national importance.

This is particularly pertinent in the concerns expressed by the Productivity Commission regarding the need for regulation, and the potential disincentive of access regulation to investment and to inefficient pricing.

The Position Paper asserts that:

> *"It is important not to overstate the extent of market power in the provision of essential infrastructure services...various competitive pressures will limit the scope for providers to restrict access and/or raise prices. This reinforces the need for the inquiry not to dismiss the 'no regulation' option, particularly given the potential costs of remedial intervention."* (p.52)

These comments invite a blunt response. There is no need to "overstate the extent of market power in the provision of essential infrastructure services"; the existence of intransigent monopolies (and the evidence of monopoly practices) had been a non-disputed fact for three or four decades pre-Hilmer. Their presence meant that not one single competitive downstream gas or electricity market emerged in this country before the structures were dismantled in the mid-late 1990s. The monopoly structure of the industry simply foreclosed such competition. This is well documented in the Industry Commission's Report in 1991. For the Productivity Commission to give even fleeting legitimacy to a zero regulation option is breathtakingly naive and constitutes an ill-advised denial of history.

Is it seriously suggested that absent such regulation as Part IIIA or the coerced restructure of the industry, the monopoly components would have voluntarily restructured themselves and recast their pricing and practices for maximum competitive outcomes? Is it really the Productivity Commission's view that in a zero-regulation environment monopoly infrastructure service providers not would seek to maximise their economic position to the detriment of competitive outcomes downstream? The evidence that such trust would be well-founded has not been presented.

2.2 The proposals would "turn back time" on energy pricing

The Position Paper (p.71) asserts that for a variety of reasons "there is a strong case in principle to 'err' on the side of investors" and to "base access prices...on less intrusive approaches involving some rules of thumb." The direction of the paper seems to be for a dumbing-down of regulatory pricing approaches and a more lenient view of monopoly practices in the name of better incentives and greater efficiency. In adopting this approach the Productivity Commission ignores the history of economic distortions and welfare losses evident in the more-lenient period pre-Hilmer.

In support of the concerns expressed by the Productivity Commission as to the inefficiency of regulation, and the impact of regulated pricing on investment incentives, the following proposals have been made:

- Proposal 8.1 would allow price discrimination "when it aids efficiency"
- Proposal 8.1 would also allow pricing above the cost of providing the service, if it doesn't "detract significantly from efficient use of services and investment in related markets"
- Proposal 8.2 would require that regulators move away from the 'building block' approach unless the regulator can "demonstrate why productivity-based approaches would not be feasible."

These proposals have the potential to turn back the clock on energy pricing. They would legitimise a number of features common in the pre-Hilmer era including the taking of monopoly rents:

- Pricing above long-run marginal costs (LRMC) (ie pricing that builds in a monopoly profit)
- Discriminatory pricing between users where some users pay well above LRMC up to their market-bearable price
- Prohibition on trading transmission capacity (required to enforce price discrimination)
- Less rigorous approach to price setting process (ie a dumbing-down of regulatory processes).

These proposals ignore the pre-Hilmer lessons. The symptoms of the old-world - without effective access regimes - included monopoly pricing, foreclosed markets and substantial distortions in investment, both upstream and downstream of transmission and distribution infrastructure.

Two examples might illustrate the nature of the old world: the first is the lack of investment in interstate gas pipeline linkages between Victoria and NSW between 1970-2000. The infrastructure monopolies on either side of the border saw no incentive to invite the other in. In NSW this meant that industry paid substantially higher prices than their Victorian counterparts, distorting the fuel-choice, cost-structure and location of downstream metals processors and power generators (there was no gas-fired power in NSW, even for peak usage before 1998). The second example is found in the energy decision-making in the Pilbara between 1980-1995 where gas pricing and gas transportation arrangements substantially hampered Australia's opportunity to develop an export-based downstream processing industry for iron ore.

The Productivity Commission's implicit invitation to permit higher prices, discriminatory behaviour and less interventionist regulatory approaches looks like a wind-back with no comment or evaluation of the limitations of the "old-world" and without any clear empirical evidence of problems with the reforms as they exist. If such evaluation was undertaken (the 1991 Industry Commission work would be a good starting point), it would suggest that the pre-Hilmer energy system was tragically flawed and that the reforms of the 1990s have been working or are at least heading in the right direction.

2.3 The impact of allowing monopoly rent-taking has been underestimated

The Position Paper appears to see the issue of fair-pricing for access purely in distributional terms, as though the only two players of relevance are the infrastructure owners and the access seekers. This is not the case.

The issue of access becomes of “national significance” by what occurs upstream and downstream of the infrastructure. National significance arises from the interest the nation has in the economic outcomes in terms of investment, pricing and export-competitiveness of energy-users and energy exporters.

Access in this context is a means to an end. It is not a simple contest between two parties. Monopoly pricing by an infrastructure owner does not simply confiscate some part of the industry value chain; it also changes the likelihood of world-competitive cost structures for Australian industry.

The issue is both absolute pricing outcomes and allocation of costs between users. The invitation of the Position Paper to allow discriminatory pricing (particularly Ramsay pricing) is a case in point. In one proposal put forward for rail pricing, users of the rail service, coal mines were invited to pay discriminatory pricing based on their profitability. The more profitable (ie more world-competitive) coal mines would pay more than the less profitable. In terms of theoretical economics (Ramsay pricing) this might improve the efficient use of the infrastructure by keeping the less efficient coal producers on the system. However it does so by cross-subsidising between users and thus reducing the world-competitiveness of our best producers! It seems to be a case of theory defeating ‘real-world’ logic and national objectives.

We should therefore not forget what national competition policy was all about. To rephrase, it is about improving the nation’s international competitiveness by removing economic distortions. We don't do that by inviting monopoly pricing practices.

2.4 There is lo evidence of lack of investment or incentive

The concerns expressed about a lack of investment and incentives are largely misconceived. They are based on theoretical concerns which do not match reality.

In Victoria, to take one example, the regulated electricity distributors propose spending over $1.5 billion in capital expenditure over 5 years. If anything, concern should relate to whether their ability to roll-in new assets to their revenue base is too easy. The same applies in gas, where distribution investment in Victoria, NSW etc is healthy if not excessive.

The issue of "incentive" is interesting and worthy of detailed examination. Does the massive revaluation of energy assets, whereby prior owners have been allowed to revalue assets well above their historical cost, qualify as an incentive to own assets?

Further one cannot simply base an argument that "regulation = disincentive" as there are many examples, mostly in distribution, where the key impact of regulated access pricing has been to enable distributors to manage market risk by rolling-in new investment for cost-recovery across the entire network.

In transmission where greenfields projects are more common, the issue is more complex with 'incentives' such as roll-in being unavailable. In such projects market risk issues are harder to manage and require foundation-shipper agreements to be in place to underwrite investment. These largely fall outside access regulation. So if there are investment issues in the context, that look like regulatory disincentives, the Productivity Commission should examine whether in fact the issue is one of market risk rather than regulatory risk.

Further, the inference that access regulation effectively caps returns at a fair return on capital is not true except in a limited set of unlikely circumstances, ie where a greenfields infrastructure promoter only ever provides regulated access services. Unregulated foundation-shipper agreements would be expected in most if not all greenfields gas transmission projects. Certainly that has been true of the Eastern Gas Pipeline, which is the most obvious case in point.

2.5 It is not appropriate for regulators to allow discriminatory pricing and monopoly-rent taking

There are other objections to permitting monopoly pricing and discriminatory pricing based around the broader role and obligations of the regulator:

- Under the Trade Practices Act the ACCC is charged with protecting the public interest in having competitive markets. It cannot sanction access pricing that builds in pricing above that applying in competitive markets without some justification relating to risk adjustment or rewards for better than benchmark performance. It cannot sanction a monopoly rent being built in solely in the name of "incentive"

- Similarly the proposal to allow discriminatory pricing ("where this aids efficiency") can only work if secondary trading is not permitted between parties paying different prices for the same service. It is not possible to envisage a situation in which the ACCC can sanction the anti-competitive move of banning secondary trading by users of energy infrastructure simply to allow discrimination to occur

2.6 The proposals are probably not workable and likely to involve greater uncertainty and disputation than before

The Productivity Commission should not assume that the proposals for higher than fair pricing and discrimination will be easily workable.

It would introduce a new test for pricing that moves from one where users can test whether the price is fair and cost-based by looking at an 'objective' and available set of financial indicators relevant to the assets used, to one where users must produce evidence over issues involving an entirely different set of matters.

Infrastructure users will be required to prove that a proposal to discriminate against them will have an inefficient impact on their or someone else's usage and on their or someone else's investment in upstream or downstream markets. This will therefore entice investment-related discounting (ie without evidence of impending investment there would be no grounds of defence against a proposal to discriminate). At best this adds one more layer to regulatory decision-making. At worst it invites argument over matters unrelated to access and therefore a new set of disputable issues will arise.

2.7 The proposals are unlikely to benefit the sort of investment in most need of support

The proposal to allow infrastructure owners to charge "higher than cost" prices is not an appropriate policy response to a concern about investment disincentives. It is likely to assist incumbent distributors and transmission players, who already have an incentive to invest by virtue of roll-in practices. It is unlikely to assist greenfields transmission (or interconnection) projects at the investment stage as their main issues relate to market risk and foundation shipping terms, not access pricing.

If rewarding one part of the industry (eg incumbent distributors) to signal incentives to invest in another segment (eg greenfields transmission and interconnectors) then it can be argued that this has already been done in the form of allowing previous asset owners to revalue their assets as the basis for pricing access. However the futility of providing incentives disconnected in time and place and industry segment should be evident; it highlights the dangers of over-compensating incumbents in the name of future investment in other areas.

Further if as a matter of public policy there are benefits to encouraging particular types of investment, eg electricity interconnectors, it would make sense to identify the best means of providing those incentives. It is our contention that the incentives would best be done via addressing the real policy barriers and distortions that stand in their way eg land-use planning, market and regulatory risk management and taxation treatment.

3. Energy Infrastructure - User Rights

The Position Paper proposes not insignificant changes to the rights that actual and potential users of energy infrastructure should have, including rights to information, due process and to a fair price.

Some but not all of the proposals deserve support:

- The proposal to ensure that access seekers are provided with more information (Proposal 6.3) is to be supported as being both fair and efficient from a regulatory and commercial perspective

- The proposal to allow pricing that is discriminatory and/or above the cost of providing the service (Proposal 8.1) underestimates the problems with monopoly pricing practices from both a practical and policy perspective

- The proposal to depart from the recently developed building-block approach to setting revenue requirements and reference tariffs (Proposal 8.2) is also premature and unwise and is likely to create a new source of regulatory and commercial uncertainty and disputation

- The proposals to create better accountability, transparency and clearer rules for appeals (Proposals 9.1 to 9.7) are all to be supported.

3.1. Information Disclosure

Proposal 6.3 provides that Part IIIA should require the provider of a declared service to give sufficient information to an access seeker to enable the access seeker to engage in effective negotiation.

This is not dissimilar to the provision of the National Gas Code that there be sufficient information provided to enable a user to understand the derivation of the reference tariff.

The proposal is to be supported for the following reasons:

- **Information Asymmetry:** Where a service is provided by a monopoly infrastructure owner it is usually the case that one party has all the data, and the other has none or next to none. In negotiation terms this gives one side a stronger bargaining position. Although information can be acquired, eg through consultants and engineers, this cost will be prohibitive for all but a few customers. A requirement of disclosure would seek to lower agency or transaction costs and redress the asymmetry.

- **Consistency with the Hilmer Report on National Competition Policy:** The Hilmer report suggested that "to facilitate negotiation...the owner of the facility should be required to provide relevant cost or other data to the party entitled to seek access" (Report on National Competition Policy p.256).

- **Informed Feedback on Regulatory Processes:**Under most existing Australian regulatory arrangements, the regulator, but not the public, has the right to see relevant data from the monopoly. This tends to create an uninformed process of input by members of the public. There is very little point in having widespread consultation if the core information necessary to conduct that consultation cannot be disclosed.

- **Avoids arbitrations**: Arbitrations are a costly and potentially misdirected means of informing the market about the relationship between costs and prices. As arbitrations are usually private the details disclosed in defence of the prices will not normally be available to other interested parties. Further, the parties financially able to afford such arbitrations are limited in number. If potential arbitration costs are say $500,000 and a customer is seeking to save 10 percent on total gas costs (or say 20 percent on transportation costs) for 5 years and the chance of success was 50-50, the only rational litigants would be those consuming over 500 TJ per annum of which there are only around 30 in a state such as NSW. For the remaining 750,000 customers, an arbitration would be financially problematic. For these customers, transparency provides a more effective means of being able to test the fairness of proposed tariffs. In overall terms disclosure provides a cheaper alternate to arbitration and should decrease its overall frequency.

- **Prevents monopoly rents:** Some but not all Australian monopolies have set prices in the past above their long-run marginal costs. However, whatever the past practices, there is a strong economic incentive for monopolies to price as high as possible. One of the key objectives of competition policy reform has been to prevent monopoly pricing. One of the most effective ways of eliminating monopoly rents is to provide consumers with the information required to prove that such pricing is occurring.

- **Prevents Regulatory Mistakes**: Even with the best regulators in the world, there are examples of changes in pricing principles that have been approved behind closed doors, which build in - unbeknown to the regulator - monopoly profits. The best protection for a regulator against the ravages of human frailty is transparency of process and cost data; so that the self-interest of third party users can assist the regulator in avoiding any inadvertent mistakes.

- **Prevents Regulatory Capture:** Much has been written about the tendency of industry-specific regulators to be “captured” by the people they seek to regulate. Important decisions negotiated behind closed doors and lacking in transparency will invite this phenomenon. Transparency is its primary antidote.

- **Maximizes the Efficiency of Self-Regulation:** If light handed regulation is to work, then there needs to be a sufficient information in the market to allow negotiations to take place and to avoid arbitration. The absence of transparency puts greater responsibility on the regulator to get it right, thus defeating any objective of minimizing the role of the regulator.

- **Enables Better Benchmarking:** Transparency of costs should also assist in establishing useful industry benchmarks. As has been argued by the Bureau of Industry Economics (and others), that where industries display monopoly characteristics, ie there are no immediate competitors, it is important to create "benchmark competition". Transparency and preset formats for the regulatory chart of accounts would enable better benchmarking

The practical experience with information disclosure is that to be useful for users and regulators, the following aspects must be present:

- There must be an obligation by the infrastructure owner to provide truthful and up-to-date information presented in a set of formats that enables a user to understand the derivation of prices

- The formats must include a predefined chart of accounts that separates non-regulated activities and enables a clear allocation of costs between regulated and non-regulated activities

- Among the cost data required would be prior year and forward estimates of operating expenses and capital expenditure relevant to the category of access services involved

- The operational data of the infrastructure is relevant including past throughput and capacity limits and constraints

- The onus of proving “unreasonable detriment” in an application that data be withheld due to commercial-in-confidence must be on the infrastructure owner

- There must be penalties for providing false information or withholding relevant information.

Given that the Productivity Commission’s terms of reference cover all industries covered by the national access regime, there may be benefit in using Schedule B of the Gas Access Code as a template.

3.2. Cost Reflective Pricing

Under Part IIIA, the CPA and access codes such as the Gas Code, users effectively have a right to participate in regulatory processes or arbitrations that take as highly relevant or fully determinative the question of what are “the costs to the owner of providing access”. This creates a right of sorts to cost-reflective pricing. It is a right that works towards fairness for users and for owners. There is no evidence that the balance in practice has been unfairly biased towards users.

The Productivity Commission’s Position Paper would change these rights by allowing “above cost” outcomes, “discriminatory pricing” (ie allowing allocation of costs disproportionate between users) and by moving away from the "building block" approach that has been developed. These proposals move from a concept that is neutral between users and owners (ie cost-reflective) to one that "errs on the side" of owners. No reason has been given for this other than a sense that it may distort incentives not to do so.

The specific proposals are these:

- Proposal 8.1 - The pricing principles in Part IIIA should specify that access prices should...
  - (allow) generation of revenue across a facility's regulated services as a whole that is at least sufficient to meet the efficient long-run costs of providing access to these services, including a return on investment commensurate with the risks involved;
  - Not be so far above costs as to detract significantly from efficient use of services and investment in related markets
- Proposal 8.2 - Consideration should be given to making explicit provision for productivity-based approaches for setting price caps in the criteria for certification. Specifically, if a 'building block' approach has been used to set a price cap, the onus could be placed on the regulator to demonstrate why productivity-based approaches would not be feasible to adjust that cap, at least in periods between cost-based 'resets'.

There are a number of objections to these proposals:

- As noted above it is not appropriate for the ACCC under the TPA to endorse discriminatory pricing or pricing that exceeds that which applies in competitive markets and which builds in a monopoly rent
- The suggestion that the "building block" approach reduces incentives (p.212) cannot logically be responded to with a proposal to simply allow monopoly pricing and remove that approach with looser ones. Higher pricing per se is not an incentive to reduce costs or to improve output. Likewise productivity measures per se do not create incentives.
- The comment of the Position Paper (p.212) that there is a "tendency for price caps based on the building block approach to merge into rate of return regulation" is an alarmist and wrongful interpretation of the facts. As Gillard J. found in the recent Victorian Supreme Court **TXU Electricity Ltd v Office of the Regulator-General** [2001] VSC 153, the building block approach is not at all the same as rate of return regulation even if there are some calculations in common; amongst other things it does not look at the company's actual returns to shareholders, it does not prevent a company from earning a return in excess of the assumed cost of capital nor does it require that they pay back profits previously earned.

- The observations of Federal Treasury should be heeded in relation to TFP approaches - "the effectiveness of price cap regimes can be undermined if the initial price base significantly diverges from efficient prices." For this reason it is only if there is a long track record that establishes prices as cost-reflective that next-generation innovations should be tried. In this respect Proposal 8.2 is at least five years ahead of its time

3.3. Public Process and Appeal Rights

In contrast to the Productivity Commission's over-zealous desire to move to next generation regulatory approaches to pricing, its proposals to streamline the rights of users to participate and to appeal are to be supported. The proposal are:

- Proposal 9.6 - Part IIIA should make legislative provision for public comment on applications for declaration and certification, and proposed access undertakings, except where it can be shown to be inappropriate to do so. (p. 245)

- Proposal 9.4 - Part IIIA should include provision for full merit review by the Australian Competition Tribunal of decisions on undertaking applications.

These proposals are good ones in that they recognise that there is a public interest in fair and efficient access mechanisms. Further that regulators will perform closer to the public interest if they are informed by the participation of all interested parties.

The proposal to allow full merits reviews is consistent with most other decisions made by administrators and regulators under State and Federal Administrative Appeals Tribunals etc. It also would undo the one-sided present position where an infrastructure owner but not a user can appeal a determination in relation to an access arrangement.

4. Summary

The key limitations of the proposal outlined by the Productivity Commission Position Paper relate to a misplaced sense that the existing access regime constitutes the sort of regulation that disincents investment and promotes inefficient usage of the infrastructure. Neither of these propositions can be supported by recent or other evidence.

Further the proposals underestimate the type of problems evident in the lesser-regulated pre-Hilmer world. It also underestimates the public interest in removing monopoly pricing and promoting world-competitive pricing outcomes in upstream, midstream and downstream markets.

NATURAL GAS PIPELINE ACCESS REGULATION

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I. INTRODUCTION AND SUMMARY[1]

We have been asked by BHP Petroleum to comment on the Productivity Commission's (the Commission) current public inquiry into the National Access Regime. The Productivity Commission is investigating Clause 6 of the Competition Principles Agreement (CPA), which requires the Commonwealth to establish a national access regime, explains when that regime will apply and details the principles with which an effective State or Territory access regime must comply; and Part IIIA of the Trade Practices Act 1974, which discharges the Commonwealth's obligations under Clause 6. We understand that the Commission's inquiry will clarify the objectives and analyze the benefits and costs of the current arrangements. The Commission will also explore alternative means of achieving the objectives of the arrangements, examine mechanisms to improve Clause 6 and Part IIIA processes, and consider the role of and relationships between the bodies involved in administering the arrangements.

This submission addresses the Commission's deliberation over access regulation's potential effects on investment in essential infrastructure. Specifically, this submission responds to the Commission's invitation for "further specific examples of the impacts of access regulation on investment in essential infrastructure."[2]

In responding to the Commission's request, this submission concerns itself with investment in gas pipeline infrastructure, in particular, and thus with the National Third Part Access Code for Natural Gas Pipeline Systems (the Code), which, as part of Part IIIA of the TPA 1974, establishes a uniform national framework for third party access to natural gas pipeline systems. We argue that while inappropriate access regulation may hinder gas pipeline infrastructure investment, appropriate regulation does not. If anything, appropriate access regulation, which characterizes that practiced under the Code, *promotes* investment in gas pipeline infrastructure.

In the subsequent sections of this submission, we demonstrate that apt access regulation should not be considered an impediment to infrastructure investment. In **Section II**, we contrast "appropriate" and "inappropriate" methods of access regulation and demonstrate the opposite impact that each can have on infrastructure investment. In

1 The authors of this report were aided in the preparation of this paper principally by Ms. Caroline Richards.

2 Productivity Commission, Review of the National Access Regime Position Paper, pp. 65.

Section III, we show that the Code serves as an appropriate form of access regulation, which helps, rather than hinders, the expansion of an integrated gas pipeline infrastructure in Australia, particularly with respect to greenfields pipeline investments. We comment on the specific features of the Code that serve to support new investment. In **Section IV**, we review the effect of appropriate access regulation on investment in gas pipelines outside of Australia, giving practical examples of how appropriate regulation has fostered investment. Our discussion of international experience focuses on North America, the birthplace of major pipeline systems and now the most comprehensively regulated. A clear story emerges from this final section. Where regulation is detailed and meticulous, investors are comfortable placing their capital into pipeline investments. The evidence from years of applying regulation in this manner demonstrates that pipeline investment is purely demand driven and is *supported* by regulation.

In light of the evidence to the contrary, we disagree with the any generalized claim that the Code will adversely effect gas pipeline investment. We do not consider the Code a credible threat to new pipeline investment, particularly because we find no evidence that similar pipeline regulation in other jurisdictions deters investment.

II. APPROPRIATE VS INAPPROPRIATE ACCESS REGULATION

In this section, we define apt and inapt gas pipeline access regulation. We then contrast their effects on gas pipeline investment, demonstrating that while inappropriate access regulation may, potentially, adversely effect gas pipeline investment, appropriate access regulation will not.

A. Appropriate Access Regulation Defined

Certain basic elements form the foundation an efficient, effective gas pipeline regulation regime. They include (1) strong primary legislation; (2) credible and comprehensive administrative procedures for making regulatory rules and adjudicating disputes; (3) accounting regulation; (4) a skilled and well-resourced regulator; and (5) clear pathways for reliable judicial review of regulatory decisions.

1. Strong Regulatory Legislation

Regulatory policies should be part of primary law, the result of legislative action and not executive decree. Primary law is the product of a deliberative legislative process, which is more likely to reflect the public interest as opposed to a few special interests. Further, primary law is harder and slower to change than executive decree is, so it provides greater certainty.

Such legislation should specify a regulatory body independent from the executive with specific duties and information-gathering functions specific to the industry. An independent regulatory body, capable of making long-term commitments and demonstrating strong rules for its actions, is needed for long-term investment in the sector on a commercial level. Without strong laws that define such a regulatory body, investment is not likely to be efficient and effective and the ability of regulators to act in the short-term interests of the executive administration are great. The World Bank (among the other multilateral aid agencies) has been a consistent supporter of independent regulatory bodies in those countries where it has had an important role in facilitating energy privatization.

In some countries (for example those with a strong and independent judiciary and a history of private utility development) industry regulation is increasing tending toward the light-handed price cap regulation in a desire to promote efficiency. Nevertheless, well-defined light-handed regimes require an exacting constitutional, legal, accounting and procedural foundation. In other words, efficient light-handed regulation requires a complete regulatory specification rooted in primary law as detailed as those supported by the World Bank in the recently restructured pipeline industries of Argentina and Mexico, for example.[3]

2. Administrative Procedures

One of the principal methods for ensuring regulatory predictability (upon which the ability to raise capital on reasonable terms depends) is to require regulatory decisions to comply with strict procedural rules. The goal of such procedures is to ensure that regulatory decisions possess a high degree of legitimacy and predictability. Such is achieved by making the regulatory decision-making process highly transparent and open to the viewpoints of potentially opposing interest groups. Such procedures dictate that: (1) regulators make decisions on the basis of publicly available evidence; (2) regulated companies and users have a right to be heard; and (3) there must be a clear path of appeal to judicial authority.

The actual form of these procedural rules depends on underlying local legal codes and practices. Nevertheless, predictable regulatory or tariff-making practices are unlikely without a clear set of administrative rules that bind the way that the independent regulators conduct their business. In the energy industry reforms in Argentina and Mexico, administrative procedures are already part of the administrative law of both countries (although, admittedly, the specific Acts were not written with regulation in mind). The U.S. 1946 Administrative Procedures Act (the general model for the others) is an effective model—requiring regulators to hold hearings, warn participants of impending rule changes, allow participation in regulatory proceedings from the affected parties and accept evidence (i.e., the elements of "due process" in the administration of regulation). Because that act constrains the actions of regulators, it heightens the level of regulatory predictability and the value of regulatory commitment.

3. Accounting Regulation

Effective regulation requires that regulators define the consistent and sustainable accounting procedures to be used by regulated companies. The early history of regulation

[3] In both countries, the World Bank supported primary legislation and a detailed regulatory law, including specifications for regulatory independence, the formulation of tariffs, accounting standards and judicial appeal.

in the U.S. was characterized by notorious accounting abuses, including overstated expenses, unverifiable investments in plant and equipment, a lack of separation between utility and non-utility businesses and overcapitalization.[4] Such abuses were effectively ended with the adoption by the federal government in 1938 of the Uniform System of Accounts. Some regulatory regimes today exhibit the same kind of accounting abuses characterized in the U.S. in that earlier era (the UK notably). The goals of good regulation are frustrated without the regulator's ability to periodically assess costs because of the lack of detailed and reliable figures from agreed accounting sources.

Regulatory accounts exist separately from statutory (*i.e.*, accounts for investors) or tax accounts primarily because regulators require much more detailed cost information to oversee the efficacy and fairness of tariff calculations (among other reasons).[5] Taxing authorities, by contrast, need only much more aggregated accounting information. Without a detailed set of accounts, however, regulators might be unable to prevent pricing mistakes or abuses by the company, such as undue cross subsidies between customers, illicit affiliate transactions or the subsidization of unregulated subsidiaries.

Regulatory accounts also exist separate from statutory and tax accounts in order to facilitate various government policies. For example, many nations have tax laws that allow businesses to use accelerated depreciation to postpone their tax burden. However, regulators typically do not allow the use of accelerated depreciation in setting prices (because of the consequent increase in near-term costs). Similarly, regulators may want to shield consumers from certain types of cost shocks by using deferral and amortization to spread costs over many years.

Regulatory accounts perform the following functions, among others:[6]

- Regulation of accounts ultimately enforces uniformity and consistency across companies in the reporting of revenues, investments, depreciation and operating costs.

4 See: Phillips, Charles F. Jr., *The Regulation of Public Utilities*, Public Utilities Reports , 1993, pages 216-217, ("Phillips").

5 *Statutory* accounts are required by law to communicate values to investors and creditors. *Tax* accounts are required to form the basis for income, excise or other taxes. *Regulatory* accounts are generally used as the basis of cost-based regulated pricing.

6 See: Phillips, pages 216-217.

- Regulatory accounts—of a more detailed nature than statutory or tax accounts dictate—are needed to distinguish between expenditures that should be charged to capital and those that should be charged to income.

- Since companies that provide regulated services are usually entitled to a market return on a fair valuation of their property, an accurate statement of a regulated company's property account is most important.

- Utility businesses must be separated from non-utility businesses.

- Regulatory accounts aid regulators in evaluating the reasonableness of prices and in answering complaints of price discrimination.

There is a very clear difference in the character of regulation in the presence—or absence—of clear accounting rules. For example, strict accounting standards (*i.e.*, the Uniform System of Accounts) rarely leave U.S. energy utilities and their regulators in major dispute over basic financial issues (like profitability, depreciation expenses or the admissibility of particular costs). In the UK, however, a major component of the reviews of British Gas conducted in recent years by both Ofgas (the gas regulatory body) and the Monopolies and Mergers Commission concern basic accounting and finance items. There is still official confusion in the UK whether British Gas's rate of profits on its capital stock or whether depreciation should be allowed on billions of pounds sterling of transmission assets. [7] Such confusion would not be possible if a uniform accounting system had been mandated in the UK upon privatization.

4. A Skilled and Well-Resourced Regulator

Implementing the requisite legislation, administrative procedures, and accounting regulation requires that the regulatory authority be up to the task. This begins with the regulator(s) themselves. The regulatory authority must be headed and staffed and by competent personnel, versed in economics, the law, accounting, and the industry itself.

The regulatory body must also be funded sufficiently to afford the experienced personnel necessary for the task. At the beginning of a regulatory authority's existence, in particular, securing the necessary skills can also involve training and contracting for the services of outside assistance for legal counsel, regulatory advice, and accountants.

[7] *The Economist* has thus referred to UK regulatory accounting as a "fiddly bit of guesswork." (See: "Don't you just love being in control?" *The Economist*, May 18th, 1996.)

5. Judicial Review

The functioning of an independent and respected judiciary—with the power to enforce its decisions even in the face of executive branch opposition—is widely considered a critical component of a credible regulatory system (and hence a viable energy sector). Countries that lack a well functioning judiciary will face problems in creating effective regulatory structures or attracting private participation and investment.[8]

Effective limits on regulatory authority in systems with well functioning regimes come from the judiciary. In both Canada and the U.S., the fundamental legal limitations on the ability of regulators to take actions that damage the holdings of utility investors (in some way or another) come from well-known Supreme Court decisions. The Courts in both countries have found that the property rights of investors in regulated companies require strict regulatory attention to invested capital.[9] In both countries, even today, normal utility tariff reviews (as well as substantial changes in regulatory rules) reference these decades-old judicial precedents—evidence of the effective control or regulatory discretion by judicial authority.

The recent dispute between US energy company TXU and Victoria's Office of the Regulator-General tested and demonstrated the strength of Australia's judicial review system. The judicial review system provided TXU with a legitamite avenue through which to appeal the Regulator-General's decision last year to cut electricity distribution charges by more than 12 percent. In May 2001, the Victorian Supreme Court rejected TXU's challenge to the powers of the Regulator-General and upheld it's right to set distribution charges and cut company revenues. A spokeswoman for TXU said, "the decision had clarified the powers of the regulator-general."[10]

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[8] See: Levy, B., and Spiller, P. T., "The Institutional Foundations of Regulatory Commitment: A Comparative Analysis of Telecommunications Regulation," *Journal of Law, Economics, & Organization*, October 1994, p. 210.

[9] In the United States, these principles were confirmed by the Supreme Court in *Federal Power Commission v. Hope Natural Gas* (1944). In Canada, the Supreme Court confirmed similar principles in *British Columbia Electric Railway v. Public Utilities Commission of British Columbia* (1961).

[10] "Court Rejects Electricity Challenge," Financial Review, May 18, 2001. See: afr.com/Australia/2001/05/18/FFXI0H7DUMC.html.

6. Summary: Basic Regulation Needs Strong Basic Rules

It is difficult to motivate large capital investments for use in immobile energy infrastructure industries where the prospect of earning compensatory profits depends solely or substantially on the actions of regulatory bodies. Regulated profits depend on the detailed and often tortuous job of identifying costs, transforming permissible revenues into consumers' prices and collecting those revenues from consumers. Regulators have innumerable ways—if they are bent on so doing—of denying regulated companies the ability to recoup legitimate and expected profits. Primary law, administrative procedures, accounting rules and judicial review are the most important features that allow regulators to exercise their jurisdiction over the efficient operation and expansion of regulated firms without damaging their ability to raise capital. .

B. Inappropriate Access Regulation Defined

The characteristics of inappropriate regulatory regimes are indeed the converse of those typifying good regulatory regimes. An additional factor that is critically important in a new regulatory regime is whether the regulator (or regulators) who would put into practice a still-abstract regime has some depth of experience in the practical skills required to implement good regulation (e.g., financial, administrative, accounting, legal, economic) and does so with an eye toward minimizing future disputes. However, without appropriate primary legislation, administrative procedures, accounting regulation, and judicial review, even the best qualified and best intentioned of regulators could not overcome a poorly laid foundation.

The creation of an effective, independent regulatory body is problematic in virtually all nations that have privatized or otherwise significantly changed their energy industry structure. The lack of primary legislation too often is a stumbling block for nascent regulatory regimes. In the interest of expedience, governments sometimes use a quicker route to reform—Executive Decree. Where the regulatory legislation (the foundation of the regulatory body) is weak, the regulatory regime will lack credibility, and investors will inevitably perceived it to be unstable. This is especially true if Executive Decree establishes the regulatory body, as opposed to the legislative process. While Executive Decree can give the appearance of enabling reform, it is all-too-easily undone by subsequent, contradictory decrees. This has been a problem in Latin America and Russia, among other places. It is vital that the regulator be credibly and durably independent of the regulated business, its customers and of the political process. The identity and jurisdiction of the regulator needs to be entirely unambiguous. This can only come from primary law.

At first glance, administrative procedures appear as though they can easily be taken care of at some later, unspecified time. Many in our experience express the view (often under the pressure of time) that: (1) proper procedures are of fairly trivial importance; or (2) virtually any set of procedures will do, so setting them out can wait as long a commitment is made to have some.

However, administrative procedures govern the creation of new regulatory rules as well as the arbitration of disputes. Transparency in price setting, access, and other "details" emanates form the administrative procedures in place. A regulatory regime whose role is not defined by a clear set of administrative rules (covering timing, the provision of evidence, the ability of affected parties to be heard, etc.) will be incapable of gaining public trust and confidence on account of its opaque decision-making process and therefore unpredictable actions. Even justifiable price changes can cause concern on the part of system users if those changes are unpredictable or are not well understood. Complaints regarding transparency are typically quite frequent in a bad regulatory regime.

The importance of accounting standards follows on from examining the role of proper administrative procedures. Accounting standards for the industry are what make costing and tariff-making procedures transparent and hence understandable and predictable to users as well as investors. A lack of detailed accounting standards that meet the particular needs of price regulation can result in someone—either the regulated company or the regulator—taking advantage of regulatory weakness to either raise or lower prices without proper justification. Without a clear, proper set of accounting standards, neither the regulator nor the users can effectively monitor regulated companies' activities. If the regulator does not enforce uniform accounting practices, it will be incapable of consistently assessing and comparing regulated companies' costs and prices.

Appeal of regulatory decisions to a credible and independent judiciary is the test of a regulatory regime. Unless such provisions exist, and until they have been used, a regulatory regime remains uncertain. A regulatory regime that lacks a clear path of reliable appeal to an independent judiciary will fail to gain investor trust.[11] This provision must, of course, be provided for in primary legislation like the Code. Legal standards for due process regarding regulatory actions that affect the value of private property only have meaning where there are recognized appeal avenues to higher judicial authorities.

C. Impacts of Appropriate and Inappropriate Regulation on Investment

Appropriate access regulation, as defined in **Section II.A**, above, will promote gas pipeline investment by giving investors the certainty that they seek when investing their capital. Although a soundly regulated industry does not offer investors the possibility of a windfall return, nor does it offer them the risk that accompanies the possibility of a windfall. Thus, a well-regulated industry presents an attractive option for risk-averse investors. Deeply-rooted regulatory legislation, clear administrative procedures, uniform accounting regulations, and a provision for independent judicial review foster the predictability that these investors seek. Subsequent sections of this paper offer practical examples that prove this point. In **Section IV**, we draw upon North American experience, demonstrating how appropriate regulatory regimes in the US, Canada, and Mexico have fostered healthy gas pipeline investment environments in these countries.

Below, we present two examples of the problems that can arise from uncertain or poorly-considered regulatory regimes.

The UK provides us with an appropriate example. A record of regulatory instability appears in the relationships between Ofgem, the UK's energy regulator,[12] and British Gas. A large part of this instability stems from the philosophy under which UK regulators operate and the procedures they use to set prices. As stated by a Director General of Offer:

> ...the UK regulator has more discretion and less need to reveal the basis of his decisions than does his U.S. counterpart. The U.S. tradition is to place all evidence and reasoning in the public record. In the UK, there is less pressure for due process. The UK regulator is deemed to be a person to whom public policy may be safely delegated, subject only to judicial review on the question of whether his actions are legitimate in terms of the act. In the UK,

[11] Australia has shown recently, as in the case of *TXU Electricity Ltd v Office of the Regulator-General and Ors*, that pathways of appeal are timely, expert and efficient.

[12] Until recently, the UK had separate gas and electricity regulators, Ofgas and Offer, which merged into Ofgem.

> neither government nor regulators have given detailed reasons for their decisions....[13]

This philosophy is combined in the UK with tariff setting procedures that (1) lack objective and consistent accounting rules and (2) base permissible revenues on uncertain forecasts of capital and operating costs (*i.e.*, the "cash flow" model). The result is that the regulator, despite its hard work in trying to institute reform, continues to surprise the companies it regulates (and their investors) by changing almost at whim the formulas that determine allowable prices.

In the case of British Gas, Ofgas published a draft series of proposals for the next five-year price cap period for TransCo, the regulated pipeline subsidiary, that had the effect of abandoning a 1993 MMC decision on calculating permissible revenues and effectively removed approximately £3 billion from the company's asset base.[14] As a result, BG's stock price fell approximately 24 percent in two days and its debt securities were downgraded three steps by Standard & Poor's, the debt-rating agency. Regulatory commitment is not credible when regulators can surprise investors in the companies under their jurisdiction to this degree in what should be an otherwise unremarkable quinquennial tariff case.

The circumstances involve complicated charges and counter charges on the part of the companies and their regulators. However, the issues are complicated in substantial part because the UK has no reliable regulatory accounting system and uses essentially unknowable determinations of future costs in setting permissible revenues. This is a very uncertain environment for the investors in these companies.[15]

Argentina provides a similar example. The role and structure of ENARGAS (the Argentina gas regulatory agency) was defined in 1992. Most of the provisions in Law 24.076 are consistent with the language in the regulatory laws seen in the U.S. or Canada.[16]

[13] Beesley, M. E., and Littlechild, S. C., "The Regulation of Privatized Monopolies in the United Kingdom." *The Rand Journal of Economics*, Vol. 20, No. 3 (August 1989), page 461.

[14] A September revision from Ofgas brought that number down to approximately £2 billion.

[15] One circumstance that perhaps prevents such practices from receiving more intense capital market scrutiny is that neither British Gas nor the electric companies have looked to external sources for capital funding since privatization (having been privatized with sufficient cash income to prevent the need).

[16] Chapter 1, Part X (Sections 50 through 64) defines the duties of the Regulatory Entity; Part XI (Sections 65-70) deals with jurisdictional processes and control and Part XII (Section 71-73) deals with infringements and penalties.

Nevertheless, there are elements of effective regulatory institutions that are not yet in place (or clearly defined) for ENARGAS.

The law contains detailed provisions for: (1) the structure, duties and financing of the regulatory agency; (2) administrative procedures and judicial review; and (3) infringements and penalties. As it is drafted, the law contains many of the structural provisions that are characteristic of highly credible regulatory agencies. These provisions include the following:

- A reasonably independent administrative panel to monitor certain private gas activities, including:
  - compliance with and changes to the franchise operating rules and investment plans,
  - potentially anti-competitive behavior,
  - dispute resolution, and
  - health and safety regulations;
- A staff that is small and technically competent;
- Legislative involvement in both the approval and the possible dismissal of regulators appointed by the executive;
- Requirements to abide by a "Law of Administrative Proceedings;"
- Specification of the route of appeal (to the National Court of Appeals); and
- A method for dealing with the continued high levels of concentration in the gas supply market (dominated by YPF, the privatized former state-owned oil and gas producer).

These are standard and useful structural requirements for regulators. Nevertheless, there are structural omissions in the law. These include: (1) uniform accounting conventions related to setting permissible revenues, determining prices at the five year reviews and tracking the financial performance of the industry; (2) specific administrative procedures for making new regulatory rules, deciding issues on the basis of evidence and resolving disputes; and (3) periodic external reviews of the regulators' methods in setting prices and imposing penalties. There are also problems of a lack of competitiveness in gas supply (separate from transport and distribution) that ENARGAS is not empowered to deal with effectively.[17]

These factors are currently causing some worry on the part of both the 10 regulated gas companies in Argentina and ENARGAS regarding long-term regulatory price controls.

[17] In the past few weeks in Argentina there has been a move in the Legislature to pass a law containing detailed regulations for gas prices. It is part of the reaction to what is seen by many in Argentina to be a missed opportunity to facilitate competition in gas production by restructuring YPF before its privatization.

III. THE CODE REPRESENTS APPROPRIATE ACCESS REGULATION

The Code is a well-considered regulatory document, worthy of serving as the basis for the regulation of existing and new interstate pipelines in Australia. It has parallels to the regulatory statutes in North America in the elements of due process, timeliness and accountability, statutes that have promoted pipeline investments, and continue to do so, precisely because they provide the regulatory certainty sought by investors. Although the Code is comparatively new and its applicability to all possible situations of pipeline development and regulation has not been tested, the ACCC has shown itself to be a highly balanced and credible regulatory agency that is subject to appeal within a highly credible judicial system. It is of no surprise, or particular problem, that the Code will evolve over time, to meet changing conditions in Australia. The ACCC's recent decisions under the Code demonstrate that the agency considers itself responsible for protecting the legitimate property rights of pipeline owners as it sets tariffs and terms of service. Even in jurisdictions perhaps less credible than Australia and North America, pipeline pricing and services regulations do not appear to inhibit investment, as the sheer scale of recent and current global pipeline investment demonstrates. As such, we see no basis for a conclusion that the Code is inhibiting or will inhibit investment in Australia.

In this section, we review a number of the Code's provisions that we believe provide the sort of regulatory certainty that pipeline investors typically seek. The sections of the Code that address the recovery *of* and *on* capital are not the only sections that provide the prospective pipeline companies with regulatory certainty, although they may be the most important. We discuss a number of sections of the Code, specifically, below.

1. <u>Section 2, Due process:</u> Due process is fundamental to regulatory certainty. Section 2 defines the Code's provision of "due process" to the pipeline company and interested parties. The pipeline company 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 we feel that there is movement in this direction. These provisions, along with the high level of detail specified in the Code, protect the pipeline company from regulatory caprice.

2. <u>Section 2.21, Timely regulatory rulings:</u> Section 2.21 (subject to 2.22) provides that the regulator must rule within six months of an Access Arrangement application, ensuring that the pipeline company 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 need for consultation and due process. Section 2.43 (subject to 2.44) continues this process for appeals and revisions.

3. Section 2.24, Protecting interests: Section 2.24 ensures that the pipeline company's interests are protected, stating:

   > In assessing a proposed Access Arrangement, the Relevant Regulator must take the following into account:
   > (a) the Service Provider's legitimate business interests and investment in the Covered Pipeline;
   > (b) firm and binding contractual obligations of the Service Provider or other persons (or both)already using the Covered Pipeline;
   > (c) the operational and technical requirements necessary for the safe and reliable operation of the Covered Pipeline;
   > (d) the economically efficient operation of the Covered Pipeline.

   The Code ensures that the regulator must look out for the pipeline company's interests, including its contractual obligations. The Code does not allow the regulator to ignore or abrogate existing agreements.

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."[18] 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 pipeline company 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 long Access Arrangement duration. While five years is the default expectation, it is explicitly *not* required. A number of "checks" on the Access Arrangement are offered, but none are required for Access Arrangements to be approved under the Code. A new pipeline seeking a longer duration (e.g., 20 years) could receive one under the Code's provisions, provided it can satisfactorily support its request. A long initial Access Arrangement period may be desirable to the pipeline company, as it can provide greater certainty for a longer period of time over the price path the company will use for its regulated services.

[18] 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 which 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 which can be the subject of a dispute under section 6."

7. Section 6, Foundation Shippers: The preface to Section 6 recognizes the importance of contractual rights, including contracts held by "foundation shippers."[19] The Code enables these arrangements to proceed without interference.

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 bear in mind the same requirements that constrain the regulator in Section 2.24:

    > The Arbitrator must take into account:
    > (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 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.

11. Section 8.3, Form of regulation: Section 8.3 allows the pipeline company 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 5 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 pipeline company wanting a "hands off" regulatory arrangement can request it while a company wanting greater certainty of cost recovery (with less up-side potential) can request that instead.

12. 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

[19] "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."

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.

13. Section 8.12, Initial capital base, New pipelines: Section 8.12 asserts 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 pipeline company 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.

14. 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.

15. 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 as to how investment cost recovery will take place.

16. 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 pipeline company 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 regulatory certainty. At the same time, it protects existing customers from paying the costs of spare capacity.

17. 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 of 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 be ensuring that they won't be subject to regulatory hold-up through either ran 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.

18. 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.

19. Section 8.43, Discount practices: Section 8.43 of the Code allows, under certain specified conditions, for the pipeline company 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.

20. Sections 8.47 and 8.48, Fixed Principles: Sections 8.47 and 8.48 deal with "Fixed Principles." Fixed Principles 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, 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 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.

IV. Regulation and Pipeline Investment in North America

The Code is similar to regulatory institutions in North America with respect to the attention it devotes to due process, careful accounting and the property rights of the pipeline companies. Thus, the fact that pipeline investment has flourished in North America, despite, or perhaps because of detailed regulatory regimes, has considerable bearing on our discussion of the effects of Code.

In this section of our paper, we discuss the regulatory regimes in the US, Mexico, and Canada in order to demonstrate that FERC-style regulation (which the Code parallels in a number of ways) supports investment in gas pipeline infrastructure.

A. United States

US pipeline regulation, established in the 1930s, served as a considerable encouragement to interstate pipeline development. The risk inherent in the construction of major pipelines was attenuated by a regulatory regime that secured the market position of pipelines and protected them from market or regulatory "hold up" actions that could damage their long-term investments. Significantly, federal regulation in the US has been so widely accepted that the pipeline industry has never mounted a deregulatory effort.

Despite the rejection by the US Federal Energy Regulatory Commission ("the FERC") of the only request for deregulation by a major US pipeline company,[20] investment in new pipeline capacity in the US is proceeding on a considerable scale. The regulation of interstate pipelines in the US has become much more detailed in recent years as the FERC has overseen the transformation of the interstate pipeline industry from vertically-integration (where pipelines own the gas they shipped) to open access (where they ship gas owned by others). This transformation has created a vigorously competitive gas market and pipeline investments have not slowed. As such, the comprehensive regulation of tariffs and terms of service for interstate gas pipelines in the US cannot be viewed as inhibiting development. Quite the contrary is true.

[20] See Koch Gateway Pipeline Company, Order on Rehearing 89 FERC 61,046 (1998).

Extensive oil and gas pipeline networks are relatively recent phenomena in the world's energy industries. Creating such networks using investor capital is a challenging financial undertaking, principally because pipeline networks require a uniquely long-term commitment of capital. The historical development of both of these industries has been strongly influenced by the type of regulatory regime each was subject to, as well as the need for both industries to limit the financial risk incurred in building dedicated, immobile and capital intensive assets.

The gas and oil pipeline industries in the US provide two quite different sets of experience that reflect on how regulation can promote or impede investment. Both pipeline networks are extensive, reaching from coast-to-coast. Also, they employ much of the same technology. However, their regulatory, ownership and financing features are very different.

The main points of our discussion are:

1. The oil pipeline network in the US is a *common carriage* regulatory model. That model impedes the creation of shippers' transport capacity rights, necessitating other mechanisms to support and/or minimize the risks to pipeline owners.

2. The US gas pipeline industry was constructed under a *contract carriage* regime, where users obtained specific contracts assuring pipeline access and transport capacity.

3. The US gas pipeline industry, with its contracts, has been unusually conducive to the creation of markets in pipeline access rights and the creation of unregulated secondary capacity—and new capacity—markets.

1. US Oil Pipelines: The Growth of a Market-Based Oil Pipeline Business in the US in Spite of Common Carriage Regulation

The US oil pipeline network began in earnest early in this century as a series of small, non-interconnected pipelines that served to move crude oil to refineries (after which the products generally moved to market in rail or roadway tankers). Important to the early history and development of the business was the question of the regulation of interstate trade. Because on many occasions these pipelines crossed state lines, the US Federal Government asserted regulatory jurisdiction over prices and terms of trade on interstate oil pipelines with the Hepburn Act of 1906.[21]

Drawing on interstate transportation of other goods (mainly roadway and waterway transportation), the law designated oil pipelines as "common carriers." As common carriers, pipelines had to stand ready to transport any oil supplies that were brought to them for shipment. This meant that an oil pipeline could not be dedicated to shipping the supplies from one field (affiliated with the pipeline owner) to the exclusion of oil from another (unaffiliated with the owner).

Common carriage requirements immediately created an impediment in financing pipelines. Since a crude oil pipeline that crossed state lines could not be dedicated to a particular field (on the one end) or refinery (on the other), this represented a greater risk to the investment in the vertical production chain. The risk was that others would enter the market and use the pipeline in competition with its owners. For this, as well as technical reasons (*i.e.*, large pipeline technology had not been explored, because barges continued to represent the least expensive way to transport oil from the principal production centers in the Gulf Coast area of the US to the major Eastern consumption markets) oil pipelines remained small in the US until World War II.

With the war, and the major disruption in barge shipments by U-boats, a national emergency (caused by the shortage of sufficient rail transport options) forced Congress to temporarily suspend US antitrust laws and to request the major oil companies to develop a plan to use major pipelines for the first time to ship crude oil to the refineries around the major consumption centers on the East Coast. After the war the pipelines built under conditions of national emergency were removed from the oil transportation business (so as not to disrupt the oil market or damage oil companies' other investments) and converted to the first effort at large-scale gas transportation from Texas to the Northeast US.[22]

[21] See *Petroleum Pipelines and Public Policy,* Arthur M. Johnson, Harvard University Press, Cambridge Massachusetts, 1967, page 32.

[22] They were purchased by the Texas Eastern Transmission Corporation and are still in use today.

The postwar demand for petroleum products in the US encouraged a thriving large-diameter oil pipeline business—both in crude pipelines and, increasingly, in product pipelines. This large growth required specific innovations in the financial arrangements, management organization and operating practices necessitated by the otherwise risky attributes of common carriage regulation (oil pipeline systems are still legally a common carrier in the US). These innovations are as follows:

1. There are very few independent oil transportation pipelines—most are integrated vertically into the major oil companies (whose holdings run from oil reserves all the way to retail petroleum marketing). Common carriage imposes great risks on independent pipelines—most of the much larger number of historical independents have disappeared over time.

2. The oil pipelines themselves, as a rule, are complemented by sizable tankage storage assets at either end, along with very clear rules on minimum shipment sizes (in thousands of barrels) and specifications for the mixing and subsequent re-refining of various qualities of crude oils. This tankage provides much of the transport flexibility that makes common carriage consistent with pipeline financing.

3. The vertically integrated pipelines, which dominate the industry, are largely joint ventures that include many, if not most, of the oil reserve holders in the origin region of the pipeline. Such joint ventures reduce the risk that pipelines will be unavailable to transport the owners' oil quantities.

4. The length and location of crude pipelines, the location of refineries and the extent of subsequent oil product pipelines all exhibit a model of cost/risk minimization within a common carriage regulatory model.

These features of US oil pipeline industry development contrast sharply with the structure of the gas pipeline industry in the US.

2. US Gas Pipelines: The Growth of an Independent, Contract-Based Gas Pipeline Business in the US in Concert with a New Style of Regulation

The interstate gas pipeline industry in the US is not vertically integrated with the production or consumption sectors and it is not regulated as a common carrier. Rather, the gas pipeline industry is subject to different regulatory arrangements to support financing and development in its large fixed, dedicated pipeline assets.

The gas pipeline industry began to grow significantly in the late 1920s and early 1930s with improvements in materials technology. At the same time, gas pipeline companies sought to bolster investor confidence and secure a source of long-term financing consistent with the long-term commitment of immobile capital represented by pipelines. That security ultimately rested in the Natural Gas Act of 1938 ("the NGA"). For a gas industry that might serve large numbers of small customers' homes, a constant and reliable supply was required. Common carriage regulation, which might interrupt one user's supplies when another one demanded access, was an unacceptable regulatory model (particularly in light of the difficulty of storing large quantities of gas in market areas). Leading up the NGA, the gas pipeline industry thus strove successfully to strike the common carrier provision from any prospective regulation. They also sought a type of regulation that would effectively ensure a continued attention to the value of the capital that they employed in the enterprise. Congress enacted the NGA with no significant opposition from the gas production, pipeline or consuming communities.[23]

The NGA opened the door to institutional financing of a much expanded gas pipeline industry.[24] Regulation of pipeline tariffs and terms and conditions, under the agency later renamed the FERC, "became the *sine qua non* for the sale of bonds financing new pipeline ventures."[25]

It is widely concluded that the pipeline industry in the US supported the NGA largely as the avenue to expanded investment. The credibility of Federal regulation was taken by those organizations with particularly long-term investment perspective—insurance companies and pension funds—to be an effective form of collateral for pipeline financing.

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[23] See: Sanders, M.E., *The Regulation of Natural Gas, Policy and Politics, 1938-1978*, Temple University Press, Philadelphia, Pennsylvania (1981), page 46. Also see: Tussing, A.R., and Barlow, C.C., *The Natural Gas Industry: Evolution, Structure and Economics*, Ballinger, Cambridge Massachusetts (1984), page 97.

[24] Problems ensued, however, because the Gas Act of 1938 allowed pipelines to restrict access to their own gas. Owning a pipeline conferred a monopoly over gas supplies. This spurred the Federal government to try gas price regulation (which prompted great litigation and, ultimately, a disastrous shortage situation by the 1970s) and, ultimately, open access to remedy the situation. The history of gas pipeline litigation in the US since the war was thus an attempt (ludicrously inept at times, to be sure) to control market power over pipeline access when the avenue of common carriage was barred as both illegal and impractical. Nevertheless, the concept of open access on utility networks got its start in these fights, and it has encouraged attempts in many other countries, including Australia, to institute open access on pipelines.

[25] Sanders, M.E., *The Regulation of Natural Gas, Policy and Politics*, op cit, page 50.

3. The Natural Gas Act of 1938

The US parallel to the Code is embodied in a number of documents, of which the primary one is the Natural Gas Act of 1938 (NGA). The NGA established regulation for the transportation of natural gas in interstate commerce. The Act's jurisdiction was solely over pipelines, not over producers or distributors. The necessity for regulation was explained in the first paragraph of section 1:

> (a) As disclosed in reports of the Federal Trade Commission made pursuant to S. Res. 83 (Seventieth Congress, first session) and other reports made pursuant to the authority of Congress, it is hereby declared that the business of transporting and selling natural gas for ultimate distribution to the public is affected with a public interest, and that Federal regulation in matters relating to the transportation of natural gas and the sale thereof in interstate and foreign commerce is necessary in the public interest.

The public interest finding is key. Without it, pipelines would have been left unregulated, regardless of any monopolistic tendencies. The same holds true for the Code. The creation of a national access regime, and of a legal document specifically aimed at ensuring that access, is the Code's reason for existence. Given the specifics of the business of transporting natural gas, general competition law has not proved to be a suitable tool. The NGA came about because it was determined that pipeline transportation was sufficiently important so as to ensure its provision—to promote and develop this service.

The NGA instituted federal oversight of rates charged by interstate gas transmission companies. The Federal Power Commission (FPC, now FERC) became the administering agency. In addition to rate regulation, the FPC held limited franchising powers. Nobody could build an interstate pipeline to deliver gas into a market already served by another gas pipeline without first obtaining FPC approval. In 1942, an amendment rounded out those powers by requiring commission certification of facilities penetrating new markets as well.

Prior to its passage, the Act was endorsed by practically everybody in the chain form wellhead to burner-tip—gas-importing states, interstate pipelines, gas producers, and gas-exporting states. Interstate pipelines and remote producers eager to sell their gas recognized that something was needed to bolster investor confidence in new pipeline construction as internal financing through holding companies was on the wane since the passage of the Public

Utility Companies Holding Act (PUHCA), an Act which addressed some monopolistic abuses via holding company structure that had been taking place. The franchising provisions of the Act offered some tangible assistance.

Some ambiguous language was carried through to the final version of the Natural Gas Act. Congress left it to the FPC to determine the details of what constituted "just and reasonable" rates for pipeline services. Under the dictates of the 1898 Smyth v. Ames decision (169 U.S. 466), which called for "a fair return on fair value," and especially given the leniency that had long characterized oil pipeline regulation by the Interstate Commerce Commission, gas pipeline companies had little to fear. The FPC departed from the “fair value” standard in the late 1940s by adopting original cost as the basis for pipeline valuation. This basis has persisted since that time, and it is not under consideration to change it.

Three major aspects of utility regulation are control over price, control over entry, and control over the extensions and abandonment of service. The first is addressed by section 4 of the NGA, which requires that regulated companies charge just and reasonable rates and not engage in undue discrimination in rates for services among customers. Under section 4, all rates and charges must me made public and kept on file with the FPC (now FERC). Section 4’s parallel in the Code is found largely in the Code’s Section 8, where the Code makes clear that “fair and reasonable” for the allocation of costs between Reference Services for which Reference Tariffs are specifically required to be cost-based. By requiring a fair and reasonable allocation of shared costs across Reference Services, and by requiring the rules governing what constitutes a Reference Service and a Reference Tariff, the Code parallels the intent of the NGA’s Section 4.

Section 7 of the NGA empowers the FPC to order the companies to extend their services (that is, to establish pipeline connections to adjacent communities) so long as such extension would not diminish service to existing customers. The natural gas companies are forbidden to abandon facilities or services without the commission's approval. Entry controls were established in section 7c of the NGA, which prohibited the building of any pipeline into a market already served by an existing natural gas company except on certification by the commission that “the present or future public convenience and necessity require or will require such new construction.” The company already in place could, however, expand its own facilities without a certificate. The Code deals with these same issues, without granting transmission pipelines geographic franchises—something done away with in the US as well. Pipelines can either apply for Coverage outright, or others can apply for the pipeline to be Covered. From the outset, the Code covered virtually every major gas pipeline.

Other provisions necessary to pipeline economic regulation are contained in the NGA's sections 6, 8, 9, 10, and 14. These provisions authorize the regulatory prescription of standardized accounting methods (including depreciation practices) for regulated companies, and to require record keeping and periodic reporting by the companies. The FERC is empowered to investigate and ascertain the costs of pipeline properties and to prohibit the companies from charging to their operating expenses unnecessary costs.

Final sections allowed the subpoenaing of witnesses and information and prescription of rules for administrative proceedings. In the interest of creating a smoothly functioning federal regulatory system, provisions were also established for wide-ranging cooperation between the FPC and the state regulatory commissions.

Like the NGA, the Code does not stand alone, but works with and within Australia's legal and regulatory structure. Each is intended to serve as a primary legal instrument in support of economic provision of gas transportation.

4. Pipeline Investment is Flourishing in the US

When we examine recent developments in the US gas pipeline system infrastructure, we see that, in the US, gas pipeline regulation is clearly promoting infrastructure investment. Between 1990 and 1998, eighteen new natural gas pipeline systems were built in the US. For the period 2000-2002, 78 projects, totaling 23.7 Bcf/d, are proposed.[26] **Table 1** lists the new systems completed between 1990 and 1998.

[26] EIA, The Evolution of Gas Markets in the US, May 2000.

Table 1: New Gas Pipeline Systems in the US, 1990-1998

Pipeline	Year	MMcf/d
Bluewater Pipeline	1995	250
Crossroads Pipeline	1995	250
Destin Pipeline	1998	1000
DIGS Main Pass Gathering System	1997	200
Discovery Pipeline	1997	600
Empire Pipeline	1994	500
Garden Banks Offshore System	1997	600
Iroquois Pipeline	1991	850
Kern River Pipeline	1992	750
Manta Ray Gathering System	1997	300
Mobile Bay Pipeline	1993	600
Mojave Pipeline	1992	450
Nautilus Pipeline	1997	600
Northern Border Extension	1998	650
PNGTS/Maritime	1998	632
Pony Express Pipeline	1997	255
TransColorado Pipeline (Southern Leg)	1996	120
Tuscarora Pipeline	1995	110

In each of these years, except for the 1994 through 1996 period, the amount of added natural gas pipeline capacity was been above 4 Bcf/d.[27] **Table 2** lists the magnitude of new pipeline capacity that came online in each year between 1990 and 1998.

[27] EIA, The Evolution of Gas Markets in the US, May 2000.

Table 2: Pipeline Capacity Added in the US between 1990-1998

Year	MMcf/d of added gas pipeline capacity
1991	4030
1992	6350
1993	6210
1994	1725
1995	1875
1996	2574
1997	6542
1998	8460
1999	5613

B. Mexico

Mexico has only recently opened itself up to private ownership in pipeline investments. There, natural gas pipeline investment has flourished quickly as a direct consequence of the stringent regulatory environment.

The natural gas industry is the most liberalized of Mexico's energy sectors. While upstream exploration and production is the sole domain of Petroleos Mexicanos (Pemex), the state-owned oil and gas company, the downstream gas market has been open to private investors since the passage of the 1995 Natural Gas Law. This law amended the Petroleum Act to permit the private ownership of pipelines for the transmission and distribution of gas, thereby enabling the private sector, both Mexican and foreign, to participate in these activities that had previously been within the exclusive jurisdiction of the State and were carried out by Pemex Gas y Petroquimica Basica (PGPB), a subsidiary of Pemex. The new law did so by limiting the definition of "petroleum industry," in the case of gas, to the exploration, exploitation and processing of gas and only to those transportation and storage functions necessary to move the gas from the wellhead to the processing plant (which includes gathering).

PGPB retains the exclusive right to make the first sale of domestic production, subject to regulation by the Energy Regulatory Commission until the Federal Competition Commission determines that free market conditions exist, although private parties are authorized to import gas for sale within Mexico.

In addition to allowing private companies to become involved in gas transportation, storage, and distribution in Mexico, the legislation liberalized exports and imports and established the regulatory framework for building and expanding transmission and distribution pipelines. The law gave birth to the Energy Regulatory Commission (CRE), which now regulates the natural gas industry. A primary objective of the CRE is to promote efficient development of the first-hand sales and distribution, transportation and storage of natural gas. The CRE's powers include enforcement of regulations, inspections of facilities, issuance of permits, regulation of prices, overall supervision of the industry, ensuring an adequate supply, security, the promotion of competition, and the elimination of cross-subsidies. Private-sector participation in these areas currently is subject to permits granted by CRE for 30 years, based on competitive bidding. Since its inception, the CRE has established the framework for a stable business environment to encourage foreign investment.

The Natural Gas Law and the CRE were established precisely to revitalize Mexico’s lagging energy industry. The clear, detailed regulation has done just that. Specifically, the regulation has had a positive effect on natural gas pipeline investment. Investment has been increasing in the recent years.

As in the US, natural gas regulations in Mexico are detailed and comprehensive. This stringency has been fundamental to promoting investment. The CRE grants permits for pipeline construction using much the same criteria that the FERC does. A company, or group of companies, wishing to construct a pipeline must prove that a market exists for their service. CRE has shown that it will issue multiple permits for pipeline construction in the same area, allowing the pipeline companies to compete amongst themselves (having been able to learn from the US’s embracing and then rejecting transportation pipeline franchising). For instance, in the case of the Palmillas-Toluca route, the CRE issued construction permits to two separate consortiums led by Tejas Gas (a Shell subsidiary) and Transnevado Gas (a TransCanada subsidiary). Transnevado subsequently backed out of its construction plan, and Tejas constructed a gas pipeline over this route.

Mexico’s pipeline construction has shown a steady climb. The CRE, within the past five years, has issued roughly 20 transportation permits for the construction of around 1,000 miles of pipe. Recently constructed pipelines within Mexico include, but are not limited to, the

Toluca-Palmillas Pipeline discussed above, Energia Mayakan, and the Sonora Pipeline. The 435-mile Energa Mayakan pipeline will deliver 370 MMcf/d from Ciudad Pemex in Tabasco to power plants along the Yucatan Peninsula. A consortium of TransCanada, Intergen, PSG International and GUSTA owns the pipeline.[28]

Numerous additional pipeline projects are under consideration. PGPB is studying a natural gas gathering line that would run from Dos Bocas to Cactus and a line that would run from Samaria to Dos Bocas. Midcoast Energy Resources, Inc., is planning to build a 59.1 mile line to deliver natural gas from an interconnect with a Pemex line in Valtierra, to Leon, Mexico, to serve industrial and residential markets. The line, which will be co-owned with Associated Pipe Line Contractors, has received a permit from the CRE.

A number of projects involve lines designed to deliver U.S. gas to Mexican power markets. Coral Mexico Pipe Line LLC has completed its $40-million project to deliver natural gas from Kleberg County, Texas, to an existing Pemex Gas line in Arguelles, near Reynosa, Mexico. The line will deliver 300 MMcf/d from southeast Texas to the Pemex network.

Sempra Energy and PG&E Corp. have announced plans, with Mexico's Proxima Gas SA de CV, to build a 212-mile natural gas pipeline. The $230-million North Baja pipeline project is designed to deliver gas to industrial and power markets in the Baja California region of northwestern Mexico.

Kinder Morgan Energy Partners is still studying a plan, previously announced by KN Energy, to build a 108-mile gas pipeline linking the MidCon Gas network in Texas, US to Monterrey, in northern Mexico.

Since 1995, 10 pipelines have been built connecting the US natural gas pipeline system with Mexico's gas pipeline system. They are listed in **Table 3**, below.

[28] Pipeline and Gas Industry Magazine, November 2000 Vol. 83 No. 11 and November 1999 Vol. 82 No. 11.

Table 3: Pipelines Linking the US with Mexico

Project Name	Pipeline Company (US)	Pipeline Company (MX)	Capacity (MMcf/d)	Start
SoCal Calexico/Mexicali Crossing	SoCal Gas (Sempra)	Proxima Gas, Enova, Pacific Enterprises	25	Jul-97
El Paso Copper Plant Export	El Paso Natural Gas (EPNG) (El Paso)	Mexicana de Cobre, an MX mining company.	78	1999
Norteno Pipeline	Southern Union Company	PEMEX	90	Jul-95
Samalayuca Pipeline	EPNG (El Paso)	PEMEX	212	Dec-97
PG&E Gas Transmission-Texas	El Paso (recently purchased from PG&E), intrastate pipeline	PEMEX	38	Jul-95
Reynosa/Pemex Export	Tennessee Gas Pipeline (El Paso)	PEMEX	215	Sep-99
	Texas Eastern (Duke)	PEMEX	350	Jul-95
Kings Ranch/Argulles Border Cross	Coral Energy (Shell, Tejas Energy), intrastate pipeline	PEMEX	300	Oct-00
Rosarito Pipeline Project	SDG&E & SoCal Gas (Sempra)	TGN de Baja California	300	2000
Valero	El Paso (recently purchased from PG&E), intrastate pipeline	PEMEX	400	Jul-95

At least five additional pipeline interconnections are currently proposed. These are listed in **Table 4**, below.

Table 4: Mexico-US Pipeline Connections Currently Proposed

Project Name	Pipeline Company (US)	Pipeline Company (MX)	Capacity (MMcf/d)	Start
Willcox Lateral	EPNG (El Paso)	PEMEX	130	Summer 2001
Midcon Roma Export Station	Kinder Morgan Energy	Midcon de Mexico	275	On hold.
PNM Gas Services Export Project	PNM Gas Services (Public Service Company of NM)	PEMEX	35	On hold.
Capacity Expansion on Samalayuca Pipeline	EPNG (El Paso)	PEMEX	60	2001
North Baja Pipeline Project	PG&E	Sempra, Proxima Gas	400-500	2003
Nogales	El Paso	Ductos de Nogales	8500	2002

C. Canada

Canadian regulation of gas pipelines is carried out through the National Energy Board. In this section, we review the regulatory regime in place for Canada's natural gas pipelines and discussing investment in these pipelines.

1. The National Energy Board

In Canada, the National Energy Board (the NEB or the Board) is an independent federal regulatory agency established in 1959 that regulates, among other things, the construction and operation of pipelines, along with pipeline carriage regimes, prices, and price methodologies.

The NEB was created to address important policy issues, such as the construction of new pipelines and the approval of long-term exports of natural gas. The NEB stated corporate purpose is to make decisions that are "fair, objective and respected." It does so through carrying out public hearings (written or oral). The NEB operates as a court of record, very similar to a civil court.

Interprovincial and international oil and gas pipelines and additions to existing pipeline systems under federal jurisdiction require the NEB's approval before they may be built. Public oral or written hearings are held for pipeline construction applications. In determining whether a pipeline project should proceed, the NEB reviews, among other things, its economic, technical and financial feasibility, and the environmental and socio-economic impact of the project.

The Board regulates pipeline tolls and tariffs under its jurisdiction to ensure they are just and reasonable and that there is no undue discrimination in tariffs or services.

When establishing tolls, the NEB traditionally examines their capital and operating costs to ensure that companies shipping natural gas are protected from unjustified high transportation costs. Tolls set by the NEB cover the cost of service plus a fair and reasonable return to investors. Major toll applications normally warrant a public hearing. However, the requirement for lengthy and costly oral public hearings has been declining, in large part due to the advent of negotiated multi-year settlements. In 1995, the NEB republished its Guidelines for Negotiated Settlements of Traffic, Tolls and Tariffs. The guidelines are intended to facilitate a negotiated settlement process which allow the resolution of toll and tariff matters through consensus building and negotiation, without resorting to a lengthy hearing process. Any negotiated settlements must still be approved by the NEB.

The NEB has conducted a generic multi-pipeline cost of capital proceeding. Capital structure and rate of return on common equity for some companies are set based upon an adjustment mechanism established in this proceeding. This mechanism has also helped to reduce the requirement for hearings.

A pipeline company's tariff contains the conditions under which transportation service is provided. The tariff includes conditions on accepting new shippers, on allocating capacity to shippers and on determining which position a prospective shipper will occupy on the waiting list for service. The Board requires that pipeline companies operate according to the principle of open access"—meaning that all parties must have access to transportation on a non-discriminatory basis. In addition, tolls for services provided under similar circumstances and conditions with respect to all traffic of the same description, carried over the same route, must be the same for all customers.

2. Provisions in the National Energy Board Act

For prices, the Act specifies that “a company shall not charge any tolls except tolls that are: (a) specified in a tariff that has been filed with the Board and is in effect; or (b) approved by an order of the Board.” (Act, at 60) Prices must be just reasonable, and nondiscriminatory. “All tolls shall be just and reasonable, and shall always, under substantially similar circumstances and conditions with respect to all traffic of the same description carried over the same route, be charged equally to all persons at the same rate.” (Act, at 62).

3. Rate of return

The NEB uses a “generic” rate of return, applying the same methodology, and final numbers, to all pipelines under its jurisdiction. In its most recent proceeding, pursuant to the ROE adjustment mechanism approved in the Multi-Pipeline Cost of Capital Decision (RH-2-94), the NEB approved a rate of return on common equity of 9.61 percent for the year 2001. The NEB based this on a 10-year Government of Canada forecast bond yield of 5.85 percent less 12 basis points to reflect the actual differential between the 30 year and 10 year bonds to produce a forecast long-term (30-year) Government of Canada bond yield of 5.73 percent for 2001.

The NEB then combines the bond data with return on equity figures. The forecast long-term bond yield for 2001 was 39 basis points lower than the 6.12 percent forecast yield relied upon in the NEB's ROE calculation for 2000. The 39 basis point yield differential between the current and previous forecasts was multiplied by 0.75 producing a downward adjustment of 29 basis points to the 2000 approved ROE of 9.90 percent. The ROE for 2001 is 9.61 percent.

4. Gas Pipeline Uniform Accounting Regulations

Canadian pipeline companies are subject to uniform accounting regulations that specify how, for regulatory purposes, these companies organize and report their financial particulars. These regulations also specify important provisions such as book asset values and depreciation practices, along with the recording of income and expenses.

5. Financial Regulatory Audit Policy

The National Energy Board ("Board") issued a revised Financial Regulatory Audit Policy applicable to all regulated pipeline companies. After several companies under the Board's jurisdiction negotiated incentive toll settlements, the Board issued letters to those companies indicating that its audits would thereafter be focused on ensuring compliance with the Oil / Gas Pipeline Uniform Accounting Regulations.

The Board decided that this limitation on companies that have negotiated incentive toll settlements could affect the NEB's ability to meet its mandated regulatory responsibilities, which include a need to monitor the effectiveness of its new processes in order to protect the public interest. The Board's primary means of assessing the effectiveness of negotiated incentive settlements was through shipper complaints. However, the absence of formal complaints does not necessarily indicate that interested parties are satisfied with the settlement as parties may lack the information and/or resources required to make such an assessment. The Board determined it should have a role to play in auditing settlements to ensure that they are working as intended.

Financial regulatory audits will be carried out on the basis of the following objectives, confidentiality guidelines, approach and procedure.

- To determine if the company's system of accounts has been maintained in accordance with the Board's Gas and Oil Pipeline Uniform Accounting Regulations.

- To determine whether the company has complied with the National Energy Board Act, decisions, tariff orders and other accounting and reporting directives.

- To verify that the financial information contained in various company applications or submissions to the Board agrees with the company's records.

- To examine whether cross-subsidies have been made at the expense of toll payers.

- To maintain up-to-date knowledge of the company, including its regard for economy and efficiency.

While the Board makes its audit reports public, it holds confidential documents obtained from the company during an audit.

In carrying out its audits, the Board relies on the opinions expressed by the external auditors on the financial statements of the company. The Board will not normally duplicate the work of the external auditors. With respect to those companies that operate under incentive toll settlements, Board staff examine information in other areas (beyond the usual regulated areas covered in an ordinary tariff proceeding) for the purposes of maintaining in-depth and up-to-date knowledge of the companies' regulated operations and assessing the effectiveness of the incentive settlements.

6. Pricing Information

A company that charges tolls shall, at the end of each three-month period of operation, furnish to the Board:

- the rate of return on the rate base obtained for that period compared with the rates of return on the rate base authorized by the Board at the company's most recent rate hearing or, in the case of a company whose rate of return on the rate base has not been authorized by the Board, the rate of return on equity for that period;

- information explaining material changes between the results obtained from charging the tolls and the forecast figures on which the tolls were determined; and

- calculations showing the reasons for the material changes in capital, traffic, revenues, expenses and rates of return.

7. Pipeline Investment in Canada is Flourishing

Regulation has not hampered pipeline investment in Canada. There has been considerable progress in recent years on gas interconnections between Canada and the United States. The Northern Border Pipeline, an extension of the Nova Pipeline, came onstream in late 1999 and connects to Chicago through the upper Midwest. The Maritimes and Northeast Pipeline came onstream in January 2000, running from Sable Island, Nova Scotia, to New England. The Alliance Pipeline is a $2.5-billion, 1,875-mile pipeline, the longest ever built in North America, and it is designed to carry about 1.3 Bcf/d of gas from western Canada to the Chicago area. The pipeline began commercial service on December 1, 2000. The Millennium Pipeline remains in the regulatory approval stage of development; it is slated to connect Canadian sources to southern New York and Pennsylvania.[29]

Numerous new pipelines have been built within Canada in the last ten years, as well. These include, but are not limited to, the US $61 million Dawn-Enniskillen loop, the US $330 million Vancouver Island Line, the US $501 million Transcontinental Pipeline System, the US $67 million Transcanada Manitoba to Ontario system, the US $2.6 billion TransCanada Alberta-Quebec system, and the $4.4 billion Foothills pipeline.

[29] EIA Country Analysis Briefs, Canada, February 2001.

V. CONCLUSION

This paper has addressed the Commission's inquiry into "the impacts of access regulation on investment in essential infrastructure."[30] Specifically we have shown that appropriate access regulation will not deter investment in gas pipeline infrastructure. On the contrary, sound regulatory regimes contain numerous provisions that promote, rather than discourage, gas pipeline investment; appropriate regulatory regimes provide risk-averse investors with the certainty they require for their investments.

We have analysed sections of the Code and demonstrated that it is, in fact, based upon the tenets of sound regulation, and thus should not hamper infrastructure investment. We have supported this point with an evaluation of North American experience, demonstrating how apt regulation in the US, Canada, and Mexico has facilitated a healthy investment environment in these countries.

Thus, we conclude that any worries that the Commission may have about access regulation deterring infrastructure investment are unwarranted, with respect to the gas pipeline industry. The Code is a sound piece of regulatory legislation, and, as we have demonstrated, good regulation facilitates investment in pipeline infrastructure.

[30] Position Paper, pp. 65.

Asset Valuation and Regulation of Energy Infrastructure Tariffs in Australia: The Use and Deficiencies of DORC

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1. Introduction.

In Australia, the owners of energy transmission infrastructure assets (e.g. gas pipelines and electricity grids) are natural monopolists safe from any practical economic risk of private sector investors or governments replicating the main trunks of their transmission networks. Following the principles set down in the *Report on National Competition Policy* (Commonwealth of Australia, 1993), Federal and State governments have established "access regimes" to enable other companies, including downstream users and possible competitors in energy supply markets, to access (i.e. rent) part of the capacity of these otherwise monopolized assets. Arrangements between asset owners and asset users are on an essentially commercial basis, intended to bring about competition in energy supply markets and reduce downstream energy costs. In exchange for access to their networks, asset owners are paid transmission tariffs according to overall amounts and structures determined within the administrative responsibilities of independent regulatory agencies, including primarily the *ACCC* (Australian Competition and Consumer Commission), *ORG* (Office of the Regulator-General, Victoria) and *IPART* (Independent Pricing and Regulatory Tribunal of New South Wales).

Federal government industry policy on tariff determination written into the national *e*lectricity and national gas codes, and reaffirmed by the ACCC (1998, pp.6-15; 1999, pp.viii-xiv), requires that tariff settings be "cost-reflective" and generally consistent with prices in efficient and competitive markets (Productivity Commission, 2001 p.198). These overriding but otherwise imprecisely articulated criteria leave regulators with wide discretion but also with the difficult task of contriving market-like outcomes where there are no actual markets. The fundamental problem is one of logical circularity – tariffs cannot be fixed at levels consistent and fair in relation to the market value of the services (energy load transmission) and service infrastructures (pipelines etc.) when in fact those market values are only determined once tariff levels are set. There is no observable market for energy transmission services independent of the regulators own decisions. Nor can regulators look to the capital markets for benchmark asset values and yields, because where observable these depend in turn on the market's observations of the regulators (i.e. on expected tariff outcomes).[1]

Undaunted by this inherent circularity, regulators have developed and relied almost exclusively on a model claimed to emulate market determinations, and described as the "building block approach" (ACCC 1999, p.x; Productivity Commission 2001, p.209). Put simply, this model categorizes the period costs of owning (financing) and operating the necessary transmission infrastructure assets and adds these together to give a maximum or upper limit (a "price cap") on allowable period tariff revenue. In general, total period costs are taken as the sum of *operating costs* and *capital costs*, where "capital costs" are defined as (i) depreciation (i.e. loss of asset value) plus (ii) the opportunity cost – that is, foregone return – caused by tying up capital (asset value) in non interest bearing physical (infrastructure) assets.

[1] Walker et al. (2000a) note that this circularity problem has long been recognized within rate-of-return price setting and regulatory regimes; several references are provided, beginning with Bonbright (1937).

Expressed as a formula, the maximum allowable tariff revenue (MAR) in period t is

$$\textit{operating expense}_t + \textit{depreciation}_t + \textit{opportunity cost}_t \qquad (1)$$

Where depreciation$_t$ is the loss in asset value $V_{t-1} - V_t$ over period t (however measured) and *opportunity cost*$_t$ is the dollar return on capital that could have been earned had the period opening asset value V_{t-1} been invested elsewhere for the duration of the period (ACCC 1999, pp.x-xiv). The intuitive justification for this formula is that asset owners are reimbursed for their (efficient) periodic operating costs and for any consequential loss of capital (depreciation), and rewarded at a specified rate of return, determined by the regulator, for their use of capital, as would fairly be expected of a rational and competitive capital market.

The regulators' tariff formula averts any circularity problem by defining entity asset value in an "accounting" rather than "economics" way as a sum of "book values", or in other words, by applying a "balance sheet" approach to the valuation problem. Individual asset book values are measured on a basis independent of the asset's use in regulated energy transmission. Possible valuation bases are current market realizable (scrap) value, "historical" or actual cost, current replacement cost and "deprival value" (a variant of replacement cost). Of these, the later has been actively considered by regulators, but rejected because of its inherent reference to future cash flows (tariffs) and hence the circularity problem (ACCC 1999, pp.x-xi).[2] Each of the other three bases of valuation applies without any circularity – specifically, the amount that an asset (such as say a pump or a pipe) cost when it was acquired, or would cost to replace, or could be removed and sold for, does not depend on how it is currently being used, or moreover on what tariffs it is helping generate.

Having escaped the circularity issue, any of these three possible valuation bases might have been adopted within the "building block approach". However, from the start and with little apparent reservation, there has been consensus between the major regulators, particularly the ACCC and ORG, that the single universally appropriate valuation basis for tariff setting is current replacement cost, or more specifically *depreciated optimized replacement cost*, commonly abbreviated to DORC. By definition, the DORC of an asset is the written down replacement cost of its optimal or most efficient (in an engineering sense) replacement. How (by what rule) it is written down ("depreciated") is another issue and generally open to negotiation, although an algorithm called "competition depreciation" has lately been endorsed by the ACCC (1999, pp.59-61, 65-70).

The Australian regulators' acceptance of DORC has significant economic and political consequences, and has attracted both support and annoyance from within the industries and companies affected. The main issue, immediately obvious to academics who have watched the waxing and waning over three decades of current cost accounting (CCA) proposals in the private sector, is that DORC valuations tend to inflate asset book

[2] Walker et al. (2000b, p.132) note that in Australia "[t]he deprival value accounting variant of replacement cost has become the dominant public sector accounting method". The institutional history of the emergence this concept is documented in Clarke (1998) and Walker et al. (2000a).

values (relative to either historical cost or market realizable value) and hence to increase any related measure of the asset owners' "capital costs", thereby increasing the regulated tariff stream flowing from energy users to transmission asset owners. The ready appeal of DORC-based tariff streams to incoming (and incumbent) asset owners has assisted governments, particularly the State government in Victoria, to maximize the proceeds from infrastructure privatizations. Moreover, the direct connection between prices gained from the sale of infrastructure assets and the basis on which they are valued on paper (on the regulatory balance sheet) has undoubtedly brought much political pressure on regulators to adopt and endorse DORC, and must in part explain why they have generally appeared so committed to its application.[3]

The economic, political and social consequences of regulators' general reliance on DORC asset valuations are clearly very significant. At worst, there is the potential to hamstring present and future Australian industrial development by inflating the costs of energy to downstream producers, thus unnecessarily rationing their use of existing energy transmission networks and known energy reserves. On the other hand, transmission asset owners have argued that an asset valuation base which leads to lower tariffs will jeopardize their profitability and therefore stifle growth and investment in new infrastructure.

Given the import of these considerations, it is essential that there be proper review of the Australian regulators' adoption and advocacy of DORC asset valuations. The purpose of this paper is to contribute towards such a review. In particular, the paper reconstructs the regulators' conceptual framework, including particularly the role of DORC in the tariff formula, and questions the analytical arguments that have been put for DORC and expressly endorsed by regulators in their published proceedings. A secondary objective of the paper is to bring to the notice of regulators and others involved in the tariff setting debate relevant aspects of the established literature on replacement cost valuation in accounting, emphasizing particularly the problems caused by their innate subjectivity.

The most contentious and consequential regulatory asset valuation decisions are to do with "sunk" (already existing) assets. Assets yet to be built (new investments) will come on to the regulatory asset base (RAB) at the same dollar amount irrespective of whether the asset valuation basis is (depreciated) actual cost (known as DAC) or replacement cost (DORC). Although the subsequent treatment of those assets' values may not be the same (see section 7 below), the likely tariff consequences of the regulator's choice between DAC, DORC and other valuation rules are relatively less significant or at least further into the future for new assets than for those already existing. Because of the priority and precedent attached to the issue of valuing the initial asset base (RAB), this paper is primarily about the valuation of existing assets.

2. The Regulators' Tariff Equation

[3] See, for example, the Victorian State Treasury submissions, emphasizing the validity and importance of DORC, to the ORG/ACCC joint enquiry on the Victorian Gas Distribution Access Arrangements (Final Decision 6 October, 1998; ORG (1998) and ACCC (1998))

The “building block approach” equation (1) for *MAR* can be written as

$$operating\ expense_t + (V_{t-1} - V_t) + V_{t-1}\, r \qquad (2)$$

where r is the effective rate of return on capital granted to the asset owner by the regulator. In principle, this percentage return is meant to equal the asset owner’s *weighted average cost of capital* (WACC), or in other words the risk-related rate of return demanded of such an investment by a competitive and theoretically efficient capital market.

The regulators’ discretionary determination of WACC (set at a real rate of return of 7.75% in the ACCC/ORG 1998 determinations) has been as controversial, and subject to the same political lobbying, as their reliance on DORC. Again there is an issue of logical circularity since the market required risk-adjusted return on investment in energy transmission assets hinges on the regulators’ choice of, and commitment to, a given figure for WACC, and to the risk of changes to regulatory arrangements in the future (“regulatory risk”). There are however more relevant external benchmarks for WACC than for RAB, such as for example typical market rates of return on “blue chip” assets, and the rates of return earned by similar entities in other countries. Nonetheless, there is no obviously correct or fair answer for WACC and the regulator can only adjudicate between the various affected parties disparate and obviously self-interested views. References on the recent Australian regulatory debate over WACC include Davis (1999a; 1999b).

Replacing the corresponding terms in (2) with the acronyms RAB and WACC, the regulator’s tariff equation is written in its now familiar form as

$$operating\ expense_t + (RAB_{t-1} - RAB_t) + RAB_{t-1}\, WACC. \qquad (3)$$

3. Theoretical Foundations of the Tariff Equation.

The tariff formula can be rationalized in terms of NPV, using the mathematical reconciliation between cash and “accruals” measures of capital costs proved by Peasnell (1981, pp.53-4) and Edwards et al. (1987, pp.12-31), and elaborated upon in the literature on “clean surplus” accounting (e.g. Peasnell 199?) and “economic value added” or EVA©.

Specifically, after being re-imbursed for their periodic operating expenditures (e.g. wages etc.) asset owners receive net cash (tariff) flows in period t equal to

$$(RAB_{t-1} - RAB_t) + RAB_{t-1}\, WACC.$$

Discounting this cash flow sequence at rate r=WACC, the discounted net present value (NPV) of the tariff stream to asset owners is

$$NPV = \sum_{t=1}^{T} \frac{(RAB_{t-1} - RAB_t) + RAB_{t-1} WACC}{(1+WACC)^t}$$

where t=T represents the time at which the regulatory asset base is fully depreciated ($RAB_{t=T} = 0$).

Simplifying this equation as follows

$$NPV = \frac{(RAB_0 - RAB_1) + RAB_0\ WACC}{(1+WACC)^1} + \frac{(RAB_1 - RAB_2) + RAB_1\ WACC}{(1+WACC)^2} + ...$$

$$..... + \frac{(RAB_{T-1} - RAB_T) + RAB_{T-1}\ WACC}{(1+WACC)^T}$$

$$= \frac{RAB_0(1+WACC)}{(1+WACC)} + \frac{RAB_1(1+WACC) - RAB_1(1+WACC)}{(1+WACC)^2} + ...$$

$$..... + \frac{RAB_{T-1}(1+WACC) - RAB_{T-1}(1+WACC)}{(1+WACC)^T} - \frac{RAB_T}{(1+WACC)^T}$$

$$= RAB_0 \qquad (4)$$

reveals that the NPV of the regulated tariff stream, calculated at discount rate equal to the regulated WACC, is equal to the amount of the initial (t=0) RAB. This result makes obvious the asset owner's economic imperative for negotiating the highest possible initial RAB. If the regulated WACC is in fact the true cost of capital, then the NPV of the ensuing tariff stream is exactly equal to the RAB granted by the regulator.

Three further results follow immediately:

(a) any asset revaluation agreed to by the regulator amounts to an NPV "gift" to asset owners equal to the amount of the (upward) revaluation. To prevent this "free lunch" the regulator must either prohibit asset revaluations or treat them explicitly as income in the tariff equation, thus reducing period tariffs in the period of the revaluation by the amount of that revaluation. The expanded tariff equation satisfying this requirement is

$$\textit{operating expense}_t + \textit{depreciation}_t + \textit{opportunity cost}_t - \textit{revaluations}_t\,.$$

(b) any new investment in infrastructure assets by asset owners offers NPV equal to the difference between the corresponding increase in the RAB and the actual cash amount invested. To fix this incremental NPV equal to zero, as is characteristic of an efficient capital market, expenditure on new assets must be brought onto the regulatory balance sheet at actual cost (which is, of course, also the then replacement cost of the new asset).

(c) NPV is a constant regardless of the time pattern of depreciation. It makes no difference over what interval assets are written down, or how aggregate depreciation expense is distributed within this interval – that is, NPV=RAB_0 whatever the depreciation scheme. This observation traces to Preinreich (1938); cf. Schmalanesee (1989), Whittington (1997, pp.9,11) and Davis (1999a, pp.7-8; 1999b, p.2).

Analogy with a Bank Account. The financial effect of the regulators' tariff equation can be described intuitively as follows. In essence, the regulator creates a "bank account" in the name of asset owners of initial amount RAB_0. Against this account, owners are paid periodic interest at effective interest rate WACC (as granted by the regulator). Interest is calculated on the period opening RAB value. Each period the RAB or account balance falls by the amount of depreciation in that period. This sum is paid to the asset owner, and equates to a cash withdrawal from the asset owner's interest bearing account. In aggregate, the period tariff includes both a sum of interest ("return on capital") and a withdrawal ("return of capital"). When at t=T all capital is withdrawn (RAB=0), cash flows (tariffs) cease. In practice RAB will likely never approach zero, because the asset owner will over time make further investments in its infrastructure assets. The amounts spent on new assets will have the same effect as cash deposits into the owners "bank" (RAB) account. Each further deposit (asset acquisition) will earn interest until fully withdrawn through asset write-downs (depreciation). An important aspect of this analogy is that all interest is paid out in cash – none accumulates in RAB. The only way to add to RAB is to invest in new assets.

The Issue of Depreciation Scheme. The economic incentives of the asset owner in relation to its chosen depreciation scheme are straightforward. Depreciation is a return of capital out of the pool (RAB) earning a regulated ("guaranteed") rate of return (WACC). If the regulated WACC is acceptable – or more than acceptable – then the asset owner will want to depreciate its assets only minimally or not at all. The reason for this is that once a depreciation expense is recognized, the owner is "paid out" that amount and hence does not earn a WACC return on it anymore. Note that neither the NPV of the investment nor its IRR (here equal to the regulated WACC) is affected, only its duration. All else equal, an investment returning a high IRR (regulated WACC) will be extended as far as possible. This is achieved by minimizing and thus effectively postponing ("back-loading") depreciation write-downs.

Constraining the service provider's economic incentive, in circumstances of a favorable WACC determination, for minimal depreciation (maximum RAB) is its obligation to pay dividends. Asset write-downs provide cash flow and in this way are advantageous.

Ultimately the asset owner will have to compromise between its competing desires of maximizing the asset pool earning the regulated WACC and at the same time paying a stream of dividends to shareholders of sufficient amount and consistency. All arguments about depreciation algorithms (e.g. straight line, "economic life", "CCA depreciation", "competition depreciation"; cf. Davis 2000, pp.4-6; King 2001) should be seen in this light.

4. Private Sector Rejection of RC Valuations as Too Subjective

DORC and its close relatives (DRC and "deprival value") have a long and exhausting history in the accounting literature. During the era of high inflation in the 1970s and 1980s there was a strong push in the UK, Australia and New Zealand for shifting the basis of external financial reporting in the private sector away from the traditional historical cost (DAC) framework onto a replacement cost (RC) footing. Ultimately, after extensive scrutiny, the RC proposal was defeated from both within and outside the accounting profession. This was for a multitude of reasons, of which perhaps the most telling was the inherent practical difficulty of measuring the RC of assets in any way "objective" or independently verifiable,[4] and hence the latitude for management interference in the asset values and related cost measures:

> There is no way in which the resultant income and capital measures can be treated as being independent of management. (Peasnell 1984, p.192)

Because of their subjectivity, Whittington, a stalwart of the RC debate and an avowed in-principle supporter of RC for financial reporting purposes (although not tariff regulation), effectively dismisses the possibility of RC methods becoming standard financial accounting practice:

> The accounting standard perspective suggests that CCA [replacement cost accounting] is, at best, a remote prospect as standard accounting practice in the UK. Systematization of the valuation base, to include more current values, possibly on a VTB [deprival value] basis, has been proposed rather tentatively. However, the subjectivity of such valuations, especially for specific operating assets, such as plant and machinery, is likely to rule them out as standard practice for some time. (Whittington 1994, pp.88-101)

DORC is Unauditable. Auditing in the sense of *independent corroboration* (cf. Wolnizer 1987) is impossible with DORC. No two firms of valuers working independently can be expected to come up with equal or even nearly equal DORC valuations. The problem is that DORC valuations embody multiple subjective and at worst completely arbitrary choices, and can only be verified when these are specified

[4] There were also problems with finding any workable concept of financial or operating "capital". These are largely irrelevant here because the tariff equation has its theoretical justification not in an accounting concept of "capital maintenance" but in its reconciliation with the NPV (economic value) of the tariff stream.

and then taken as given. In the end, the only independent verification is of the arithmetic.[5]

The unavoidable discretionary choices that underlie all DORC valuation occur in response to the following problems:

(a) the *asset definition* problem. The cost of replacing an asset depends on how that asset is defined. Is it the physical item in question (e.g. a pipe) or it's future "service potential" (the latter is the usual accounting definition of an asset). Since the measurement required is ORC rather than RC, it is implicitly the latter. But what specifically constitutes "service potential", and for how long and to whom, and by what measure? This raises the issue of expected useful life. Just how much service potential does an existing asset have left? Is it 25% or 55% depreciated in this regard? Will it be bypassed and will the energy (e.g. gas) available at its source remain economically extractable? Who can say, and on what objective grounds? There are no objective (uniquely sensible) criteria on which to answer any of these questions. The valuer has no alternative but to rely on discretionary "professional judgement" and therefore retains the ability to arbitrarily affect the bottom line.

(b) the *optimization problem*. By what engineering criteria is an asset or arbitrary grouping of assets optimized? How far is the engineer allowed to go in hypothetically re-designing the asset base? Is it only a matter of fine tuning or should the engineer start with a blank canvass (e.g. greenfields Melbourne)? What customer base (throughput) is relevant, is it the current situation or a projection of demand in 5 or 25 years time? Does the notion of asset optimization relate only to cost or more to a set of engineering parameters? If both, which should be given more emphasis? Moreover, if the notion of an engineering optimum depends on cost, is there a different optimum for every different cost level?

(c) the *quote variance problem*. If the valuer relies on just one estimate of the RC of a particular asset (however defined for the purpose of getting a quote) then the valuation is subject to high sampling error (variance). If a larger sample of quotes is drawn, which should be given the most weight?

(d) the *aggregation* or *non-additivity* problem. In general, the RC of a conjunction of assets $\{a, b, c, d, e\}$ is not equal to the sum of the RCs of the individual assets $\{a\}$, $\{b\}$, $\{c\}$, $\{d\}$, $\{e\}$. Nor is it equal to the sum of the replacement costs of any mutually exclusive and jointly exhaustive subsets of those assets, such as for example $\{a, b, c\}\cap\{d, e\}$. Moreover, by re-partitioning the asset set into another of its possible groupings, such as say $\{a, b\}\cap\{c, d, e\}$ or $\{a\}\cap\{b, c, d\}\cap\{e\}$, the aggregate replacement cost can be made arbitrarily higher or lower. To escape this arbitrariness, practitioners suggest that the appropriate asset bundling is that which minimizes aggregate RC, a rule consistent with the notion of "optimized" RC. The problem with this criterion is that it generally leads to a very high level of aggregation. Natural economies of scale mean that hypothetical asset replacement

[5] Walker et al. (2000a) have recently shown up this deficiency in the financial reports of a string of water and electricity utilities in NSW. Whatever their theoretical appeal for the purposes of financial reporting, the endemic subjectivity and ultimate arbitrariness of RC valuations remains their Achilles heal.

cost is minimized, in the limit, when infrastructure is replaced as a "single" asset. But at such high levels of aggregation, RC quotes are bound to exhibit extreme variance from one estimate to another, based on different guesses about the potential economies of such large scale construction. The "least cost" rule is therefore ineffective in removing subjectivity and discretionary latitude from the bottom line. By culminating in the entirety of the firm's assets being defined as one, it effectively defeats the purpose of a "balance sheet" approach to asset valuation.

Bureaucratic Suppression of Criticism. During the private sector RC debate of the 1970s and 1980s, DORC style asset valuations were disparaged and ultimately rejected for their incorrigible subjectivity and inherent susceptibility to "creative accounting". There is nowadays a consensus among academics who endured this debate that little of what was learned has reached or been heeded by those now advocating RC for use in the public sector:

> …what does seem to be unjustifiable is the apparent lack of a coherent approach to the issue of "current value" accounting in the non-business sector. There seems to have been no concerted effort to draw lessons from the ultimately unfavorable attitude of business. The various regulations give the impression of as many ad hoc choices, sometimes leading to possibilities of opportunistic accounting policies, sometimes resulting in figures which even the entities involved have difficulty interpreting. (Camfferman, K. 1998, pp.???)

> Clearly those who have promoted the drift of both DV [deprival value] and ODV into the public sector have either not heeded that experience with CCA, DV and related concepts in the private sector, or did not know of it. If it is the former, then the public sector reformers must be considered to suffer a certain lack of candor. (Clarke 1998, pp.???)

RC based accounting has been promulgated at all levels within the Australian public sector. In 1994 the *Steering Committee on National Performance Monitoring* (SCNPM 1994) set out to institutionalize a RC framework by its publication and wide dissemination of asset valuation guidelines closely resembling those of the various CCA (current cost accounting) proposals of the 1970s. By supporting RC (in fact "deprival value") without qualification or reference to any of the relevant academic or professional literature, this publication (known as the "red book") effectively suppressed all existing criticism of RC valuation methods, thereby raising questions of the competence if not integrity of the political process that led to RC being adopted (cf. Johnstone and Gaffikin, 1996 and Johnstone and Wells, 1998). The same questions now arise in regard to the regulators' effectively unqualified and seemingly apolitical support for DORC. In all their various publications dealing with the asset valuation issue, there is no mention whatsoever that RC has a long history of rejection in the private sector.

The other more astounding precedent overridden by regulators, and curiously not mentioned in any of their written deliberations, is that in the USA where asset valuation for the purposes of tariff setting has a 100 year history and a vast literature, replacement cost based asset valuation has been either not taken seriously or considered and rejected. The authoritative American text on asset valuation for regulation purposes, Bonbright et al. (1988, pp.296-8), rejects replacement cost valuation as being neither economically appropriate nor practically administrable. For example (see also later quotes):

> ...the answer must lie in a recognition by practical minded judges, commissioners, and experts, that estimates of the cost that would be incurred in replacing the service by means of a new type of plant if the existing plant were to disappear into thin air are altogether too speculative and too litigious for purposes of feasible administration. (Bonbright et al. 1988, p.298)

5. The Regulators' Argument for DORC

Asset owners formal submissions to regulators and the written determinations of the regulators themselves (particularly ACCC and ORG) contain repeated albeit scantly supported claims that replacement cost asset valuation, particularly DORC, has a derivation in economic theory (e.g. ORG 1998 pp.9; ACCC 1999, pp.43-4). This view has been promulgated and recited to the point that its wisdom is widely taken for granted, albeit without demonstration or acknowledged authority (cf. Productivity Commission 2001, pp.216,220,222).[6]

The economic argument on which the regulators justify their commitment to DORC, as best as can be construed from their published statements (cf. King 2001, pp.14-5), is that RAB=DORC emulates rational market settings by producing the highest possible tariffs short of those at which a new entrant might be encouraged to duplicate the existing provider's infrastructure (and compete for those tariffs). According to this argument, a profit maximizing asset owner, operating opportunistically in a free market, would stretch tariffs to this level for the long run:

> ...DORC is the valuation methodology that would be consistent with the price charged by a new entrant into an industry, and so is the equilibrium price that would prevail in the industry in long run equilibrium. (ACCC 1999, p.39)

The economic theory underlying this argument is built around a construct called "Tobin's *q*", after its inventor, Nobel prize winning economist James Tobin. Tobin's *q* is defined as the ratio of the value of the firm to the replacement cost of its assets. That is:

$$q = \frac{M}{ORC},$$

[6] The consultant on tariff setting issues with apparently most influence over the ACCC is economics Professor, Stephen King, of the University of Melbourne. In several of his papers King has argued that DORC (and possibly the building block model in general) is inappropriate in this function (e.g. 1996, p.295; 1997, p.198; 1998, p.3). For example, King (2000, p.7) writes "…as I have noted elsewhere, the contestability justification for DORC is dubious and it may not be desirable to replicate the fictitious path of revenues that result from [this] model" (see also p.2). However, in his most recent work, King (2001, p.5) concedes that despite his previously oft stated critique of DORC, he will for the sake of assisting in current deliberations take DORC as given. This resignation would seem to be indicative of the ACCC's committed and apparently ideologically axiomatic acceptance of DORC.

where *M* is defined as the market value of the firms securities (debt plus equity) and *ORC* is the minimum (optimized) cost of replacing its current productive capacity, making allowance for the fact that some of its assets are not of the same capacity as when they were new (i.e. they are used). Tobin introduced the *q* ratio as a way of measuring the level of monopoly power of the firm (Tobin, 1969; Brainard and Tobin, 1968) and of assessing the market incentive for further capital investment. Large *q* is associated with large surpluses or economic rents (profits exceeding costs, including capital costs), these being capitalized by the market in its assessment of *M*.

In the absence of monopoly rents, the value of *q* is expected to be near one. For the value of *q* to exceed one, the market value of the firm (the present value of its projected net cash flows) must be greater than the *RC* of its assets. In these conditions there are incentives for new entrants or for expansion by existing firms, with the effect that prices will be reduced and *q* driven towards a value of one.

> ...The essence of the argument is that for a competitive firm, one would expect q to be close to one, and as we examine firms with increasing monopoly power (increasing ability to earn above a competitive return), q should increase. If a firm's q is greater than one, the market value of the firm is in excess of its replacement cost. If there is free entry other firms could enter the industry by purchasing the same capital stock as the existing firm. Furthermore, they would anticipate an increase in value over their investment because its market value would exceed its cost. Thus, in the absence of barriers to entry and exit, *q* will be driven down toward one as new firms enter... (Lindenberg and Ross 1981, p.2)

According to Tobin's argument, *q*=1 characterizes a firm operating in a competitive market in long run equilibrium. In these circumstances, the firm is extracting the maximum attainable income stream (product price) without admitting any hint of opportunity to potential price cutting competitors. Conversely, if *q* was less than one there would be no incentive for existing firms to renew their assets and the number of competitors would shrink to the point where prices could be raised and *q* pushed back towards one.

On the basis of this logic, *q*=1 is taken to be the definitive measure of an appropriately regulated monopoly stripped of any economic rents:

> ...a firm which is regulated so as to earn no monopoly rents would have a q close to one. A monopolist, however, who can successfully bar entry and is not adequately regulated will earn monopoly rents in excess of ordinary returns on the employed capital. The market will capitalize these rents, and the market value of the firm will exceed the replacement cost of its capital stock, that is q will persist above one. (Lindenberg and Ross 1981, p.2)
>
> It can be argued that in a competitive market, if a supplier charges a price above minimum efficient cost of supply, then new entrants will be attracted into the market by the abnormal profits that are available; as a result, market prices for outputs, and the market value of business enterprises supplying those outputs will tend towards cost. ...The above propositions are consistent with the theory of the relationship between the market value of assets and their replacement cost developed by the economist James Tobin. The ratio of the market value of the

company's debt and equity to the current replacement cost of its assets is known in the finance literature as Tobin's Q. ...Tobin argued that when Q is greater than 1 (that is, when capital equipment is worth more than it cost to replace), firms have an incentive to invest, and that they will stop investing when Q is less than 1 (when equipment is worth less than its replacement cost). ...On this basis, it is accepted, in principle, that the use of ODRC asset values and a market based estimate of the WACC is intended to mimic the outcomes of a competitive market... (ORG 1998, p.5)

To measure *q* the regulator has to find the minimum ("optimized") RC of the firms used assets, or more precisely, of the cost of replacing the partially depleted productive capacity represented by those used assets. To prevent confusion with the replacement cost of all new assets, this cost is labeled ORC*used*. The measure intended by Tobin is then

$$q = \frac{M}{ORC_{used}}.$$

Because there are no second hand markets for the kinds of assets in question (excepting scrap metal markets), regulators have treated *DORC* as a proxy for ORC_{used}, and hence implicitly re-defined Tobin's *q* as

$$q = \frac{M}{DORC}. \qquad (5)$$

The final step in the regulators' effort to set Tobin's q=1 is to fix the initial regulatory asset base, RAB_0, such that the market value of the entity, *M*, equals *DORC*. Thinking of *M* as the NPV of the tariff stream, this requires merely that RAB_0=*DORC*, since NPV=RAB_0 as shown by equation (4) above.

6. The Argument for DORC is Sophistry

The regulators' position, reconstructed as faithfully as possible above, is that DORC based tariffs build in and thus mimic the discipline of a competitive market. Although superficially appealing, this argument is simplistic and deceptive for the following reasons at least:

(a) A new entrant in the market for energy transmission services would have to pay full (undepreciated) ORC to duplicate or bypass existing infrastructure. There is no second hand market on which one can buy a used *in situ* electricity grid or a gas pipe network, or even the individual components thereof. Hence, provided that the DORC value claimed by the existing asset owner is less than the actual (i.e. "true") ORC, there is no possibility of competition. To the contrary, asset owners can value depleted (used) assets at a book DORC up to the amount of their true ORC – that is, book ORC can greatly exceed true ORC – and thereby lay claim to a stream of tariffs consistent with all transmission assets being new rather than used.[7]

Proof. Consider the position of a potential new entrant under the following four simplifying assumptions: (i) zero inflation, (ii) zero growth in the tariff market, (iii) constant ORC (i.e. no technological change), and (iv) new assets last "forever" (i.e. to the point that subsequent cash flows make no difference in PV terms). The new entrant expects to take from the incumbent a proportion ρ of the existing tariff stream, tariffs being determined by the regulator using the incumbent's "book DORC" (as per tariff equation (3) above).

In present value terms, the new entrant would then earn tariffs worth

$$\left\{P + \frac{ORC}{(1+WACC)^T}\right\}\rho$$

where *ORC* is the (constant over time) replacement cost of all new assets, *WACC* is the regulated and actual cost of capital, *T* is the time (number of years from now) at which the incumbent's assets will require replacement, and *P* is the present value of the tariff stream to be earned by the incumbent from those assets prior to their eventual obsolescence.

There is no obvious basis on which to estimate the new entrant's possible market share, but to be consistent with the regulators' argument, it must be assumed that ρ=1, meaning that the new entrant will completely displace the incumbent, taking over the entire tariff market. This is of course an utterly unrealistic possibility (see below), and can be treated only as a "theoretical" limiting case. Its event would require circumstances where, for example, the new entrant, before making any investment, tied all asset users into very long term (e.g. 30 year) contracts. Equivalently, the new entrant might theoretically be a co-operative of all asset users, bound together by an effectively permanent contract to self-supply using newly constructed assets.

The indifference condition for any new investment, is NPV=0. Hence, a potential new entrant is motivated to invest provided that the PV of its tariff revenues equals the cost of all new assets, *ORC*. Thus, taking ρ=1

$$\left\{P + \frac{ORC}{(1+WACC)^T}\right\} = ORC.$$

implying

[7] Given the effectively unlimited lives of many transmission networks, regulators must preclude asset valuations (write-ups) to prevent asset owners, without any further investment, from continually increasing tariffs in line with increasing network replacement costs.

$$
\begin{aligned}
P &= ORC\left\{1-\frac{1}{(1+WACC)^T}\right\} \\
&= (ORC \times WACC)\left[\frac{1}{WACC}\left\{1-\frac{1}{(1+WACC)^T}\right\}\right].
\end{aligned}
$$

Noting that the term in square brackets is the usual mathematical "annuity factor" for a *T* period annuity at discount rate *WACC*, it is evident that the minimum tariff revenue acceptable to a new entrant in the time prior to the incumbent's replacement date equals (or is equivalent to) an annuity of amount ($ORC \times WACC$) per period. This is proof of the ability of the incumbent to set its book *DORC* up to a limit of actual *ORC*, and effectively hold it constant at that level over all of the years before it replaces its assets, without offering the incentive necessary for a new entrant.[8]

To allow for this market reality, the regulators' must substitute true ORC for book DORC in their measure of Tobin's *q* (equation (5) above), in which case q=1 occurs when tariffs are set on an ORC rather than DORC basis. It is, however, unlikely that this less naive application of the Tobin's *q* argument would be acceptable to regulators. The political costs of determining tariffs explicitly and effectively perpetually as if all existing infrastructure was new (in fact, as if it had all just been built at current new replacement cost) would likely overshadow the niceties (e.g. intellectual kudos) of a model based more carefully in economic theory.

The following quotation summarizes the ACCC position, and is correct to the point that it concedes that there is little practical likelihood of any system bypass (new entrant) apart from possibly some peripheral links in national infrastructure networks:

> …any value that is in excess of DORC is likely to imply pricing of services that will expose the service provider to being by-passed. While the significant entry and exit costs that characterize electricity [energy] transmission make large-scale duplication of the existing system unlikely, by-pass may be feasible at the edges of the network. (ACCC 1999, p.xi)

The fundamental mistake, however, is that the theoretical asset value threshold, up to which there can be no threat of a new entrant, is not DORC but ORC, as demonstrated above. The ACCC argument is therefore invalid by its own economic logic, with the practical ramification that tariffs will almost certainly be fixed at levels significantly higher than necessary according to the ACCC's intended economic logic.

(b) Yet more realistically, it is likely that despite being appreciably higher than DORC, ORC also grossly underestimates the level required of RAB to entice a new entrant. Even at tariff levels well above those based on DORC or ORC, the real world possibility of major network bypass is likely to remain negligible (cf. King 1998, pp.3, 10). Moreover, even if tariffs were high enough to warrant a competitor, or user co-operative, contemplating duplication from scratch of such massive infrastructure, what market share would such a new entrant be guaranteed when the incumbent could hit

[8] Note that if ρ is taken to be less than one, as is undoubtedly more realistic, the incumbent can set DORC not merely at ORC, but at approximately (*DORC* / ρ) for small ρ (e.g. at 5×DORC for ρ=0.2).

back with cut rates commensurate with the relatively very low marginal capital costs attaching to sunk assets? Moreover, at this point the two competing networks would both be sunk, forcing the competitors into either sharing the market or a price war based in the extreme on short run marginal costing. Neither prospect can have any appeal to a potential new entrant.

It is almost too ridiculous to contemplate two (or more) rival infrastructure owners sharing the market. A new entrant would not likely invest with the prospect of say a 50% market share unless tariffs were greatly in excess of their existing book-DORC (albeit possibly inflated to true ORC) rates. Thinking in no more than these simple terms, tariffs would have to be based on a RAB (book DORC) of double-ORC or more before any genuine possibility of economically driven duplication could occur. Given the manifest risks, technological and other barriers to entry, and general political inconceivability of any investor, private or government, duplicating already functional and typically much less than fully-utilised energy transmission networks, the RAB level truly required to prompt such a decision is hard to imagine. In reality it is only in circumstances where existing infrastructure assets are at or approaching full usable capacity, or grossly below par (e.g. technologically outdated or greatly inefficient in terms of operating costs) that there is actually any threat of a new entrant.

The practical effect of this market reality is that incumbent asset owners, establishing their initial RAB are virtually unrestrained by the risk of competition, contrary to the regulators' supposed economic logic. In practice, initial DORC could be set at double-ORC and there would still be negligible risk of a new entrant. The only effective constraint on existing asset owners' initial DORC valuation, apart from any indirect benchmarking by the regulator, is the level to which the "independent valuers", hired by asset owners to find this value, are ready to stretch. Given the known failures of "independent auditors" of the highest professional repute in other, inherently less subjective asset valuation contexts, the analogous economic incentives applying to engineering based DORC-valuers in tariff setting should be of great concern to regulators.[9] The potential for "creative engineering" is perhaps as much a problem with DORC as its flawed theoretical foundations.

In summary, the Tobin's *q* argument for DORC valuation is theoretically and practically ingenuous. At a theoretical level, the problem is that in markets requiring entry-level investment of such scale and complexity, potential new entrants will surely not be attracted unless expected tariffs are considerably higher than, rather than merely equal to, those based on DORC or even RC. As a result, the practical as opposed to theoretical upper limit on the existing service provider's book DORC is not actual or "true" DORC but some unknown, possibly large multiple thereof. Moreover, book DORC can equal and probably greatly exceed true ORC without any realistic threat of competition. This must be obvious to asset owners, and is bound to encourage pervasive overstatement of asset values (ORCs and thus DORCs). From this perspective, the market discipline purportedly inherent to tariff settings based on DORC is more a product of economic sophistry than economic theory.

[9] The valuer J.P. Kenny (commissioned in March 1996 by the Gas Council to audit the AGLGN ORC estimates) revealed its own dissatisfaction with what was manageable and conceded that it was only the time and other constraints imposed on it that justified its "interactive" (with AGLGN) approach to the AGLGN valuation. See Johnstone (1999) for general discussion regarding this valuation process.

7. Broader Economic Argument against Replacement Cost

In discussion above, the Tobin's *q* argument for DORC valuation is considered and rejected on its own terms. Widening the economic criteria on which replacement cost (DORC) valuation of existing assets is evaluated, leads to a considerably stronger rejoinder. The following economic arguments are all relevant and all point to DORC as either having no special importance or being flawed and bound to produce undesirable outcomes. These arguments are provided not in any order of importance.

(i) DORC Not Necessary to Ensure Continued Optimal Asset Use

Economic theory reserves special treatment for sunk assets. These are assets which have been built and are in place in given physical condition as the result of previous decision making. From the point of view of optimal resource allocation, sunk assets should be viewed only in terms of what they can still contribute and what they could be sold for. If they are more valuable for what they can add to future production, they should be retained and used. Otherwise they should be sold for their remaining net realizable (scrap) value (NRV). Moreover, what they would cost to replace is of no relevance to present or future decision making. The entity has already built them and the current cost of doing so (again) is irrelevant to any present or future decision of how best to utilize or scrap them.

Taking this resource allocation perspective, regulators must ensure that assets are valued at or above their NRV. If the value attributed to an asset in the RAB of a regulated firm is lower than its NRV, the firm will rationally sell the asset (its NRV will exceed the NPV of its contribution to the tariff stream). The economic lower bound on the RAB is thus NRV (cf. Whittington 1997, p.5; King 1998, pp.1-3). Provided RAB is not less than NRV, existing productive assets will remain in current (presumably optimal) use. Apart from the fact that for specialized infrastructure assets, DORC is generally greater than NRV, the economic objective of continued optimal allocation of existing assets affords no special significance to RAB=DORC.

(ii) DORC Harms Downstream Allocative Efficiency

Given the importance of energy transportation tariffs to users and their customers along the production chain, it is essential that regulators think carefully about actual rather than theoretical (e.g. DORC) capital costs. The marginal capital cost of using an existing asset when that asset has little realizable value is by necessity very low. Moreover, marginal access costs are greatly overstated if capital charges are based on DORC or any asset valuation significantly higher than NRV. This leads to systematic underuse of existing transmission assets by energy users. King (1996, p.293-5; 1997, p.198; 1998, p.3) refers to this unfortunate consequence of RC based asset valuation as a type of allocative inefficiency. In essence, users ready to pay the "true" (long run marginal) cost of access are priced out of the market by tariffs significantly greater than marginal cost:

> The deprival value methodology promoted by the draft electricity access code will set an initial base for transmission utility assets that significantly exceeds scrap value. These inflated valuations of existing, sunk assets will feed into retail electricity prices, resulting in a reduction in allocative efficiency. ...The valuation rules chosen by the NGMC [National Grid Management Council] are likely to be administratively difficult, contentious and inefficient. (King 1996, p.295)

> To the degree that regulated asset valuations feed into uniform prices that exceed (congestion adjusted short-run) marginal cost, either directly or further down the production chain, then the deviation of price from marginal cost will lead to a reduction in trade from the economically efficient level. Such a reduction leads to what economists call an "allocative inefficiency" or a "dead weight loss". It represents a decrease in gains from trade from the production and consumption of the relevant product(s) compared to the best achievable level of gains from trade. (King 1998, p.4)

Closely related arguments on allocative efficiency underpin the rejection of replacement cost valuation by Bonbright et al. (1988):

> With a public utility system operating at a scale at which further enhancements in rates of output can take place with less than a proportionate increase in operating and capital costs (conditions of decreasing unit costs), such rates will exceed the incremental or marginal costs of the service. Yet, under the economists' theory of socially optimum pricing, the important relationship between prices and costs is an equality, under long-run equilibrium conditions, between prices and *marginal costs*. Hence, if socially optimal resource allocation were to be accepted as the primary objective of ratemaking policy, as the replacement-cost advocates insist, what would be required is not a mere transfer from original-cost standard to a replacement-cost standard, but rather a transfer from any standard to a standard of incremental cost. ...if we accept provisionally the assumption that most public utility enterprises are operating under conditions permitting the enjoyment of further economies of scale, and if we also assume that current replacement costs of service would be higher than historical costs, the acceptance of a replacement cost principle would seem to be a step in the wrong direction. (Bonbright et al. 1988, p.297)

From an obvious practical viewpoint, there is something wrong with a tariff base that works against expanded and perhaps even existing use of a gas or electricity transmission network currently at much less than full capacity. For a country or economy to build such a long-lived infrastructure at great cost and then not use it to anything like its available capacity for the reason that it would cost a lot to replace verges on economic absurdity. It might be reasonable to restrict usage of something which has already been built (a sunk cost) if usage of itself meant added costs, such as "wear and tear", and thus added maintenance and refurbishment costs, or if additional usage brought forward the time at which the network was no longer large enough and required parallel enlargement. But in the case of Australian gas pipelines, main trunks are typically at approximately half or much less than full capacity and the additional throughput does not cause wear and tear or any economic loss. Rather, the life of the network, if not effectively infinite, is limited primarily by corrosion rather than usage. Each period of underuse represents an irrecoverable opportunity to make something of an asset which is already in place and able to be used at essentially negligible marginal capital cost.

It could be argued that access prices which are "too low" themselves result in allocative inefficiency by encouraging the establishment and expansion of user businesses which cannot remain viable once existing network assets require replacement and tariffs are increased to match those costs of replacement (i.e. once the new assets came onto the RAB at cost). However, given the currently relatively low use of the existing infrastructure and its likely very long engineering life, this argument has much less weight than in more normal circumstances.

(iii) DORC Provides Existing Asset Owners with a Free Lunch

Perhaps the most disconcerting argument for regulators against revaluation of existing assets to DORC is that every extra dollar allowed onto the regulatory balance sheet (RAB) amounts to a dollar of present value in the pocket of asset owners (paid by the shareholders of asset users and downstream industry and other consumers). This is because under the regulators tariff formula (3) each dollar granted in RAB locks in place a future tariff stream with NPV (at discount rate r=WACC) of one dollar. By writing up the value of existing assets from whatever their current book value to DORC, the asset owner profits *prima facie* by the amount of that write-up (revaluation). This NPV windfall – and consequent share price increase – is achieved by a mere book entry with no actual cash outlay.

Whittington (1994, 1998) made a similar observation in relation to some British gas and water privatizations. It was typical in Britain that the amounts paid by the new private owners of these entities were significantly less than aggregate asset book values. Whittington warned that tariffs based on book values rather than the actual cost (AC) asset base would present the new asset owners with large wealth windfalls at the expense of gas and water consumers who would be left to pay the inflated RAB (rather than cash investment) based tariffs:

> To adopt a replacement cost or current cost approach at this late stage would involve a very large transfer of wealth from the consumer to the shareholder, which would be inconsistent with the requirement that the regulator strike a balance between these interests by allowing a return sufficient to justify the shareholders' investment but not excessive from the perspective of the consumer. (Whittington 1998, p.4)

The legacy of inflated asset values according to Whittington is that regulators will have signed off on a tariff stream that over time looks increasingly anomalous (Whittington 1994, p.93).

In Australia, the case of AGLGN (Australian Gas Light Gas Network) differs from the British experience only in that the company already owned all existing assets. AGLGN has been arguably even better treated than the British companies, in that it is has been allowed a large upward shift in its asset values above depreciated cost, and consequently a significantly enhanced tariff stream, all for no additional investment at all. It is difficult in the AGLGN case to value objectively the “free lunch” allotted to the company by the regulator’s acceptance of DORC. When a DORC based tariff stream is bought by additional investment, as in the circumstances described by Whittington and those of the Victorian privatizations, the NPV windfall is measured by the difference between the amount paid and the deemed RAB on which subsequent tariffs are based. But when a RAB=DORC based tariff stream is simply decreed to an incumbent owner whose existing assets have no objective current market value – that is, no value independent of their regulated (deemed) book value – there is no theoretically relevant benchmark against which to compare the NPV of the new tariff stream.

Perhaps the only meaningful comparison is that of the so-called “line in the sand approach”. This was a notion initially favored by IPART, where to get around the problem of the non-existent market value of existing assets, the regulator worked backwards taking pre-existing tariff levels as a pragmatic starting point. The imputed asset value is then the capitalized value of future tariffs, where their existing level is specified and taken as given like a “line in the sand”. Taking this approach, the windfall to the existing owner can be gauged by simply comparing the new DORC based tariff stream with the old tariffs as they existed when regulatory reforms and “access regimes” were initially introduced.

In the case of AGLGN, DORC based tariffs are appreciably greater than their pre-existing levels. Since these tariff increases have been achieved without anywhere near corresponding investment in new assets, it is reasonable to argue that DORC has presented AGLGN with an NPV (and thus share price) windfall. The amount of this windfall is obscured by doubts over the legitimacy of pre-existing tariff levels. For example, one point of view put by AGLGN is that these were “artificially” low and therefore not commercially sustainable. The economically logical response to this is that because AGLGN assets were already sunk, any tariff level exceeding that based on scrap value was “sustainable” in the strictest economic sense:

> A ruthless application of economic logic might suggest that as the assets are sunk assets with no alternative use except as scrap, the initial capital base should be close to zero. There is no opportunity cost where capital has been sunk. No regulated revenue stream has to be awarded to induce investment to create what already exists or to keep in place what has no alternative use. (Lim and Dwyer 2001, p.25)

From this perspective, AGLGN was really in no position to argue. Quite to the contrary, the regulator might have chosen to enact a distinction in principle between sunk assets and those not yet built. Sunk assets could have been valued at DAC or even lower, even at NRV (scrap), without prompting any misallocation of resources. Even at RAB approaching NRV, AGLGN would have no economic choice but to use existing assets in their existing (presumably optimal) way. When seen this way, the regulator’s decision to treat existing and new assets alike was unnecessarily generous. By opting essentially arbitrarily to base tariffs for existing assets on DORC, regulators have guaranteed the profitability of asset owners and gambled that infrastructure users and downstream energy consumers will cope without politically manifest damage to their profitability and economic expansion.

(iv) DORC Not Necessary to Promote New Investment.

The underlying economic rationale of the tariff equation (3) is that asset owners earn a "market" rate of return on their investments. This is achieved equally whether new investments are brought onto the regulatory balance sheet (RAB) at DORC or DAC; or more precisely at ORC or AC, since for new assets there is no depreciation. Moreover, for a new asset RC=AC by definition, and assuming the investment is "optimized" (i.e. there is no lower cost way to get the same result), ORC=OAC=AC. Provided that subsequent asset revaluations are precluded under either an ORC or AC approach, it makes no difference practically whether the amount spent on new assets, and added to the RAB, is called RC or AC (ORC or OAC). Either way, the PV of the ensuing tariff stream is equal to the cash amount invested and hence the NPV (at r=WACC) is zero, as expected of an efficient capital market.

Given that for new assets DORC≡DAC, it is curious that a view persists that unless regulators adopt DORC, there will be no sufficient incentive for asset owners to invest. It is clearly in the asset owners' interests that regulators work under this presumption. From their standpoint, any use of DAC, even if only for new assets, would leave the gate open for a shift away from DORC for existing assets also, and hence possibly large tariff losses. This would explain why the premise that DORC is a pre-requisite for new investment has been voiced so frequently during the Australian regulatory debate. Less explicably, however, regulators seem to have accepted the investment friendliness of DORC on technical grounds.

For there to be any difference between DORC and DAC in regard to new assets, regulators must envisage that DORC and DOAC asset values (and thus periodic tariff flows) will not remain the same over time despite their initial equivalence. This could be for two reasons. The first is that DORC and DAC depreciation patterns may be different. This is a likely explanation given that the ACCC advocates "competition depreciation" as essential to DORC, but not DAC. Of itself, however, a difference in depreciation flows makes no difference to the NPV of the tariff stream (see above) and hence does not explain why DORC rather than DAC is technically necessary to secure new investment. A better explanation is that regulators foresee subsequent asset revaluations (book value increases without new investment) under one approach but not the other, or by different criteria under the two valuation schemes. Indeed, in its *Draft Statement of Principles*, the ACCC clearly acknowledged its anticipation of periodic DORC revaluations:

> The NEC [National Electricity Code] does not preclude the regulator from periodically revaluing the regulatory asset base according to a valuation methodology such as DORC. (ACCC 1999, p.49)

The Admissibility of Future Revaluations. The "no free lunches" principle rules out asset revaluations – that is, increases in RAB by mere book entry – unless these are treated as income, using the extension of the usual tariff equation explained above. There is, however, some confusion surrounding this principle, caused by the regulators' determination of WACC in real (i.e. net of inflation) terms, and the technical mechanism used to achieve this effect.

There are two methods by which to calculate the "return on capital" element of the tariff formula so as to lock in a given real rate of interest. The first is to leave the initial RAB unchanged (except for period depreciation) and multiply this figure by the nominal interest rate equivalent to the given real rate. For example, to achieve a real rate r_r , the RAB is multiplied by the nominal rate

$$r_n = (1 + r_r)(1 + i) - 1$$

where i is the rate of inflation.

The second method, thus far generally adopted by regulators, is to first "inflate" (i.e. re-scale) the RAB by multiplying it by $(1+i)$ and then multiply this new RAB figure by the given real interest rate r_r. The result (dollar amount) is obviously the same using either mathematical approach. The disadvantage of the regulators approach is that it gives the impression of breaking the "no revaluations" principle.[10] Whether in fact it does depends on answers to the following two questions:

(i) Is the criterion that new investment earn NPV=0 intended to hold in nominal or real terms? If it is determined that the appropriate ("market equivalent") return to investors is some fixed *real* rate (e.g. 7.75% real), then increasing RAB by the inflation factor $(1+i)$ before multiplying by that interest rate is admissible, and technically does not break the NPV=0 (no revaluations) rule. Whittington (1997, p.6) understood that this is what was intended when he argued that asset users bear all inflation risk.

(ii) Is it intended that the Tobin's q argument will be applied continuously over time rather than merely as a way to get an initial RAB? The dynamic rather than static application of q would involve repeated DORC revaluations, applicable whenever the cost of entry (asset replication by a competitor) increases. Revaluation according to this criterion amounts to inflating RAB not by a general price index (such as the CPI) but by an industry (asset) specific index. The scale factor is not $(1+i)$ but something much more narrowly related to the construction costs of the specific infrastructure assets in question (and therefore much more subjective). Changes to RAB made on this basis are likely to break the "no free lunches" (NPV=0) rule. If the replacement cost of infrastructure assets rises by more than the general inflation rate, then the asset owner gains a tariff increase in real terms and thus a real NPV windfall. The reverse is also true, meaning that in theory the owner runs the risk of asset replacement costs, and thus tariffs, not keeping pace with inflation.

Depending on the answers to these questions, the relative effects of DORC versus DAC in regards to new investments can be summarized as follows.

[10] Aware of this problem, some regulators have shifted calculations onto an explicitly nominal basis (i.e. dollar return on capital = nominal RAB $\times$ nominal WACC); see for example the discussion in ACCC (1999, pp.24, 32) and the calculations of IPART 2000, p.112.

(i) If DAC and DORC are inflated according to the same price index – say the CPI – then the corresponding tariffs flowing from new investments will always be the same (assuming the same depreciation scheme).

(ii) If DORC is inflated according to an industry (asset) specific index and DAC according to a more general price index such as the CPI ("indexed DAC"), the choice in regard to new assets between DAC and DORC is effectively a choice between tariffs rising with the CPI and tariffs anchored to industry-specific asset price shifts. This amounts simply to a choice between two different inflation rates. These rates might differ markedly if for instance new technology was to reduce the price (replacement cost) of energy transmission infrastructure assets while asset prices in the wider economy increased. Generally, however, both sets of prices are likely to increase, in which case the tariff effect of a choice between DAC and DORC for new assets will tend to be small compared to its effect in regard to existing assets

The results above indicate that DORC has no theoretical advantage over (indexed) DAC in encouraging new investment. Apart from any differences caused by different depreciation schemes, DAC based tariffs will follow a similar pattern over time as those based on DORC. Both will increase with price increases, DAC with the CPI and DORC with whatever index or revaluations are allowed by regulators. Indeed, an investor who does not want to risk real tariff reductions as a result of technical advancements (reductions in infrastructure costs) will prefer DAC over DORC. If DORC has any advantage as far as encouraging new investment, it is that asset owners will see it as more able than DAC to be manipulated upwards at a rate in excess of general price increases. This is, of course, hardly the kind of advantage that should be welcomed.

8. Treatment of Easements

Easements are the legal rights under which infrastructure owners were permitted to build their networks across land owned by other parties (e.g. farmers). The DORC doctrine, adhered to most purely by the ACCC, treats easements like any other asset. Again this is for reasons of economic principle, namely the principle of ensuring that the RAB equates to whatever total costs a new entrant would currently incur to replicate the existing network:.

> The normal DORC methodology would assign values to such assets reflective of their market value. …The advantage of this approach is that the valuation remains comparable to costs faced by a potential entrant …. (ACCC 2000, pp.45-6)

Easements represent the reduction ad absurdum of DORC. For the most part, they have been obtained historically by existing asset owners, with the authority of government legislation, at zero or low cost. And yet having obtained these "access corridors" for generally little or no outlay, asset owners are now to be paid a return on their current market values (however determined) as if they were purchased today at today's market values. The DORC valuation of easements, more than any other asset, shows up the readiness of regulators to allow asset owners returns on investments that were never made. By insisting on the theoretical necessity for DORC, regulators find themselves bound to provide asset owners a conspicuous “free lunch”. Moreover, this is not only a free lunch but also a long lunch, since the ACCC (1999, p.45) maintains that easements do not depreciate like other assets (and hence will remain on the regulatory balance sheet in perpetuity).

Apparently less committed ideologically to DORC than the ACCC, IPART in New South Wales has decided that unlike other assets DORC does not apply to easements. Its decision is to include easements in RAB at their actual costs. The rationale provided for this decision is revealing. Rather than conceding that there is any general absurdity about DORC based tariffs for existing assets, IPART distinguished easements from other assets on the basis that they will never be replaced and hence will never present asset owners with any additional cost:

> The issue of the treatment of easements highlights the difference between the assessment of the DORC from the perspective of a potential new entrant and that of the incumbent. For the incumbent, existing easements formerly acquired will not need to be replaced. Hence, such costs will not form part of the forward looking costs of maintaining and replacing existing capacity. (IPART “Pricing for Electricity Networks and Retail Supply”)

The first problem with this explanation is that much of the physical infrastructure asset base is virtually permanent, requiring only maintenance rather than replacement, and should for consistency be valued the same way. And second, the supposed rationale for DORC is not about “the forward looking costs of maintaining and replacing existing capacity”. These costs, particularly those of new investments, will be financed by capital markets, which exist for this very reason. The theoretical basis for DORC is actually backward looking – its rationale is to reimburse the asset owner for its incurrence of depreciation and opportunity costs of capital.

It is evident that by advocating DORC on grounds of economic principle, regulators find themselves painted into a corner when it comes to valuing easements. The IPART way out is to fudge, retreating conveniently to DAC and thus avoiding the patently embarrassing free lunch guaranteed by DORC. The ACCC solution is to bluff, insisting on easements at DORC as logically part and parcel of a grander economic plan. Lim and Dwyer (2001, p.26) observe that it is fortunate for the ACCC that there are no Roman built viaducts currently in use by infrastructure owners in Australia. Rewarding their current owners at DORC, and thus making downstream industry and energy users pay for the work of the Romans’ slaves, as if it was new and built at today’s prices, could hardly be seen as a triumph of economic reasoning.

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