AGL Submission to Productivity Commission Review of the National Access Regime
June 13, 2001

My name is Bruce Connery. I hold the position of General Manager Regulatory Affairs with Agility Management. Agility Management is wholly owned by AGL. Today I represent AGL. My involvement in economic regulation of gas infrastructure commenced in 1986 when I was appointed to manage the regulatory affairs function for AGL. In 1988 I was appointed industry representative on a three person Ministerial Working Party on gas regulation in NSW. My department has been involved in review processes:

- under the gas access code: for AGLGN NSW (twice); AGLGN ACT; EAPL; Central West; and NT Gas; and
- under the Tariff Order which provides the framework for electricity distribution access pricing in Victoria; the year 2000 review;

AGL is a member of the investor group which submitted a response to the Position Paper prepared by NECG. Twenty four organisations endorsed the response – four industry associations, twenty investors in infrastructure including gas, electricity, airports, and telecommunications.

Pricing Principles

The NECG submission makes the point that current regulatory systems expose infrastructure owners to regulatory risk which is unnecessary and inappropriate in the context of the Commission's Proposal 8.1 which is designed to encourage efficient investment in infrastructure.

At the outset I wish to make the point that we do not blame regulators for much of what we consider to be less than appropriate regulation. Our regulatory systems impose significant demands on regulators to do things which, because of the informational uncertainties facing them, are bound to increase risk. In addition, regulators are exposed to significant pressures from interested parties including gas producers, electricity generators, large industry users, consumer groups, and infrastructure owners, and to significant pressure, real or imagined, to comply with the expectations of governments.

I want to demonstrate by way of illustration the inappropriateness of those aspects of the current principles, including the absence of some principles, which give rise to the uncertainties identified in the NECG submission.

In summary the NECG submission argues that, to remove unnecessary and inappropriate risk, pricing principles should:

- not permit stranding of assets;
- require that 'efficient' costs be revealed through the operation of incentive regulation (rather than require regulators to estimate them);
- provide for investors to know the regulatory cost of capital to be set initially;
- require that the risk element of the regulatory cost of capital be fixed for the life of the investment; and
- provide for pre-investment compacts or the application of regulation similar to the Petroleum Resource Rent Tax (PRRT) for greenfield or risky investments.

This presentation will cover:

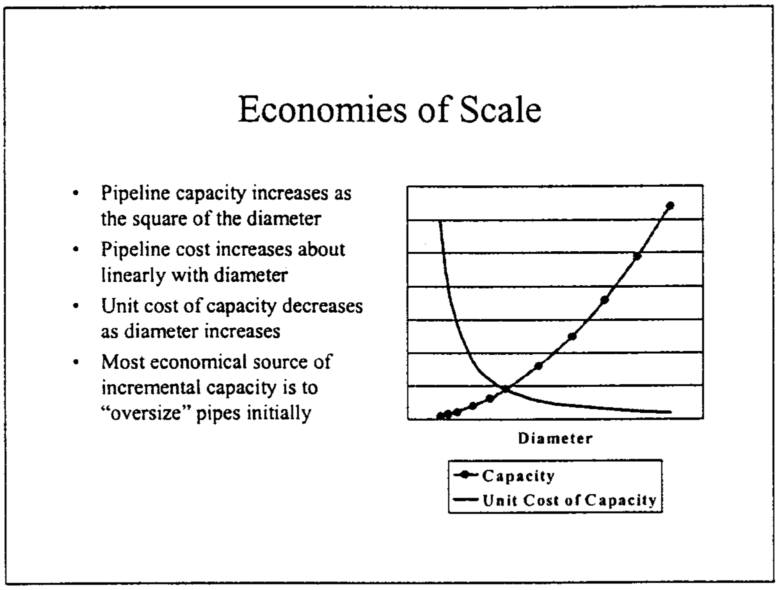
- some undesirable consequences of exposing investors to asset stranding;
- the limitations of benchmarking in the search for 'efficient' costs;
- incentive regulation as mechanism to reveal 'efficient' costs;
- the need for investors to know the regulatory cost of capital;
- the implications of changing the risk component at price resets; and
- the option of a system modelled on PRRT for regulating risky projects.

Some undesirable consequences of exposing investors to asset stranding – examples from gas

The NECG submission made the point that access regulation in Australia leaves it open to regulators to strand part or all of an asset if market circumstances have changed, or if changes in technology would result in a different investment today, and that the threat of asset stranding creates risks, increases costs, and acts as a deterrent to efficient investment.

We will draw on the National Third Party Access Code for Natural Gas Pipeline Systems (the Gas Code) to provide some illustrative examples.

However, before turning to the examples it will be useful if we first describe the economies of scale that lie at the heart of the gas transmission and distribution industries.



Other things being equal, the cost of an installed pipe varies with some power of the pipe diameter, usually less than one. The capacity, however, increases at something more than the square of the diameter. As a consequence there are significant economies of scale that can be realised by installing a few larger pipes rather than a lot of smaller ones. In the past it has been the practice of infrastructure investors to err on the side of installing larger rather than smaller pipes to take advantage of those economies. However, a number of provisions of the Gas Code are likely to have the effect of discouraging that practice with consequent loss of efficiency.

Redundant Capital
Section 8.27 of the Gas Code allows a regulator to remove from the regulatory asset base 'Redundant Capital' associated with assets which cease to serve, or which provide reduced service. Before doing so, the regulator is required to take into account the uncertainty that such a mechanism would cause and the effect that uncertainty would have on the cost of capital and the economic life of the assets.

Therefore the Gas Code provides for asset stranding, but it does recognise that this risk has a cost that must be factored into regulatory prices.

The Gas Code contains an analogous provision to deal with oversized new facilities. Section 8.19 provides for the cost of oversizing to be set aside in a Speculative Investment Fund. This Fund is not included in the regulatory asset base unless, and until, the additional capacity is used.

It is our view that the risk of asset stranding via the redundant capital provision or the Speculative Investment Fund provision will deter investment in larger, more economical pipes in anticipation of demand growth. Thus when growth materialises, relatively more costly reinforcement or duplication is required resulting in a net cost to the community. That is, it is our view that the community would be better served if there was no provision for capital to be made redundant.

For example, we suggest that the oversizing of the first leg of the Central West pipeline to Dubbo in NSW to meet the projected needs of an extension to Tamworth, would not occur today[1]. The pipeline today would be sized for the loads en-route to Dubbo alone making an extension to Tamworth significantly more difficult to justify.

Stranding by bypass
Regulatory pricing needs a rationale, it has to be capable of explanation. However, the requirement for rationality can lead to exposure to the risk of bypass, the reality of unintended price discounting and, in the context of regulatory pricing, revenue and asset stranding.

This may not be an issue if not for the fact that the risk of stranding may cause asset owners to adopt infrastructure designs and constructions which remove bypass risk but at the cost of efficiency, especially loss of economies of scale. The following example is illustrative of the issue.

Customers near a major trunk are serviced by an off-take which, as it tracks from customer to customer, initially travels away from the trunk, then turns back towards it to connect to the last customer in the group, customer X.

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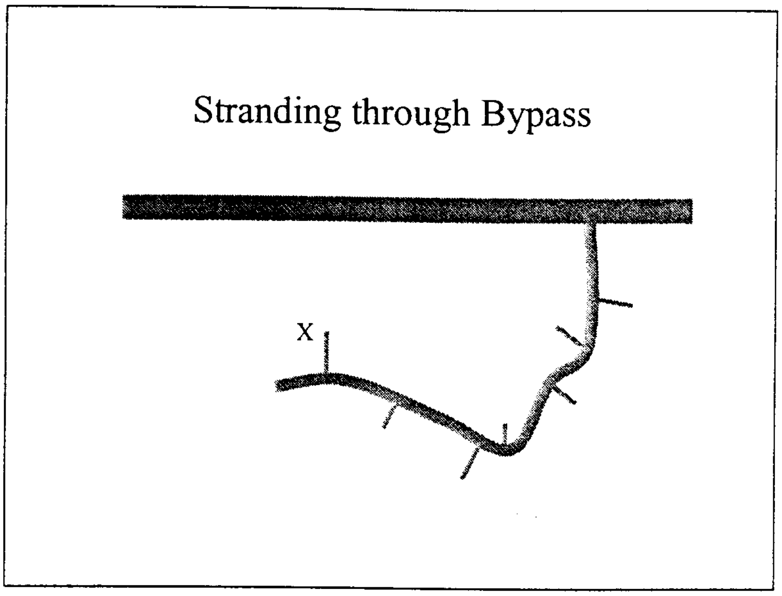
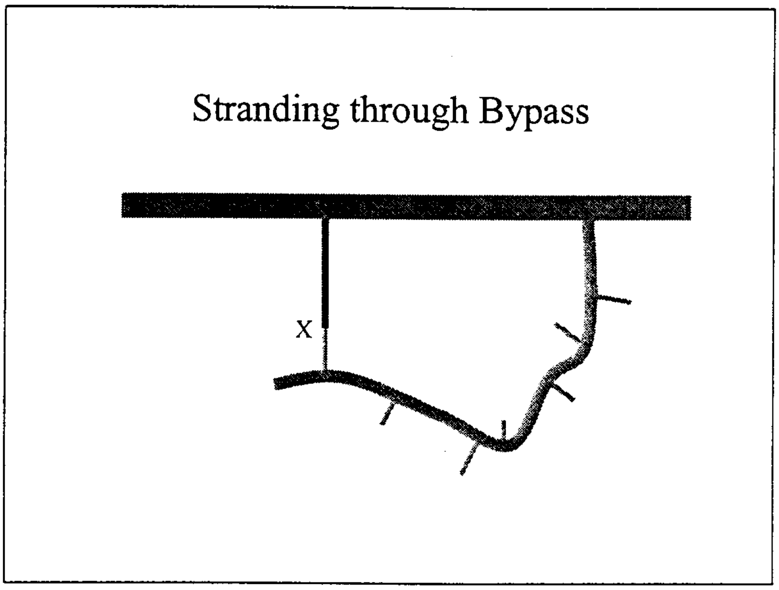
[1] The CW pipeline runs from Marsden to Dubbo, is 255 km long, and the diameter needed to service projected load was 6 inch. The cost of a 6 inch pipeline was approximately $27M. It was possible that this pipeline could in future be extended north-east to Tamworth. However this would require duplication of approximately 130km of the 6 inch line (to Alectown, near Parkes) at a cost of $10M to $15M in future. Instead of duplication in future, an 8 inch diameter pipeline could be installed at the outset to Alectown. The cost of the additional 2 inch diameter to Alectown, which doubled the capacity of this segment of the pipeline, was about $3M. The additional cost of duplication over and above the cost of increasing the diameter from 6 inch to 8 inch could undermine the economics of an extension to Tamworth.



On this occasion, the rationale used for determining prices is a form of distance pricing known as 'follow the molecule' pricing. For customer X, the distance driver includes the whole length of this off-take. However, X is closer to the trunk, as the crow flies, than is the distance that underpins his pricing. X threatens to bypass the existing service by tapping into the trunk and building a line of shortest distance to his premises.



To avoid the bypass, the infrastructure owner discounts his price below the regulatory tariff. In effect, part of his asset has been stranded.

The Gas Code does provide for 'prudent discounts' to be rolled into the overall revenue requirement and be recovered in reference tariffs. However, bypass discounts are not 'prudent discounts' under the Code.

In its 1997 Access Undertaking AGLGN, the operator of AGL's gas network in NSW, employed 'follow the molecule' pricing and was then faced with the threat of bypass leading to price discounting below the regulated tariff. In its 2000 Access Arrangement the company adopted zonal pricing and again experienced revenue losses from bypass discounts which could not be recovered. It is our view that it is not possible to devise a tariff policy for a complex network which will meet the needs of regulators for explanation which does not leave a network exposed to bypass risk.

In future, an infrastructure owner can avoid bypass risks by designing and constructing its network to be bypass proof. However, this design will not be optimal and will not produce the extent of economies of scale that come from conventional design. Rather, design and construction would reflect bypass opportunities. In the example given above, AGL would not extend the existing offtake to X but build a new, more expensive, direct connection to the trunk. That is, the existence of the threat of bypass is likely to lead to economic loss.

Limitations of benchmarking in the search for 'efficient' costs

The NECG submission refers to the risk that arises when regulators are required to determine regulated prices which provide for recovery of 'efficient' operating and maintenance costs. It makes the point that regulators will not usually have the expertise to estimate 'efficient' costs with sufficient precision to set prices and, to overcome their informational deficiencies, regulators have turned to cost benchmarking.

The submission then quotes Vogelsang to explain why most owners of infrastructure have little or no confidence in benchmarking approaches to efficient cost determination for use in setting regulated prices. Vogelsang argues that efficient cost benchmarking "is risky for a utility to the extent that its costs differ from the yardstick by virtue of such factors as geology, climate, population density, local wage rates, taxes, or the like"[2].

I would like to take you through a cost benchmarking exercise which provides a good example of the issues raised by Vogelsang. This example, which comes from benchmarking conducted by the American Gas Association in 1995, relates specifically to the cost of laying gas pipes, but similar issues arise with O&M costs.

The US benchmarking.

A significant difficulty for benchmarking studies is the establishment of a reliable and consistent base of input data. It is not sufficient to rely on a potted data base, even if this data base is a compilation of publicly reported information against uniform accounts. To make meaningful comparisons between different players detailed analyses are required to ensure consistency between what is included in 'costs'; and consistency in accounting practices.

Even with standardisation at the data collection level, results cannot be compared directly. Some attempt must be made to 'normalise' results for the factors referred to by Vogelsang, i.e. those factors that are outside the control of the distributor. Then, having done all that, the results cannot be taken as being precise.

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[2] Ingo Vogelsang, *A 20-Year Perspective on Incentive Regulation for Public Utilities*, ACCC Regulation and Investment Conference, Sydney, March 26-27, 2001.

A real life example will indicate the complexity of the task. The American Gas Association (AGA) has coordinated an annual benchmarking process for about 10 years. On each occasion a number of key subject areas are benchmarked. In 1995 one of the areas was "new construction of distribution mains". Given the nature of a gas distribution business, the cost of putting main in the ground is very significant.

AGA goes to great lengths to ensure consistency. It defines what is meant by each subject – the following slide gives the definition for "main piping new construction".

Main Piping New Construction

General Definition – All activities related to the construction and installation of distribution main piping additions

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It lists the activities involved in each subject area – the following slide gives the list of activities for main piping construction.

Main Piping New Construction
Activities

- Utility coordination
- Site preparation
- Traffic control at job site
- Surface preparation and removal
- Excavation
- Boring or jacking
- Ploughing
- Shoring
- Spoil removal
- Purging
- Fitting, welding or fusion of pipe
- Coating of joints
- Pressure of non-destructive testing
- Placing pipe in trench
- Installation of cathodic protection facilities
- Tie-in of piping to existing mains
- Backfilling
- Installation of tracers
- Inspection of coating and c/p facilities
- Surface restoration and general clean-up
- Odorization of new pipeline

Note: Excludes replacement of mains

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It identifies the non-controllable and controllable factors which impact on the amount of work required in the subject area – the following slide lists those for main piping construction.

Main Piping New Construction

Non-Controllable	Controllable
- Number of feet of new distribution main piping installed	- Type of equipment
- Soil type	- Type of pipe
- Developed locations	- Crew size
- Undeveloped locations	- Crew mix
- Surface type	- Type of backfill
- Length of job	- Type of shoring used
- Pipe size	- Joining methods
- Level of compaction required	
- Obstructions	
- Traffic control	
- Extra depth required	

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It then 'normalises' for non-controllable factors by adjusting the length of pipe installed by multipliers for each of the non-controllable factors. The multipliers are the best judgement of a panel of distribution company experts. An adjusted length of installed pipe is calculated from the multiplication of actual installed length by the relevant multipliers. The following slide gives the multipliers for main piping construction.

Main Piping New Construction
Multipliers

Soil Type:		**Length of Job:**	
Stable Soil	1.00	Greater than 1500 feet	1.00
Loose Soil	1.25	600 feet thru 1500 feet	1.10
Rocky Soil	1.50	Less than 600 feet	1.25
Locations:		**Surface type:**	
Undeveloped	1.00	Dirt	1.00
Developed	2.00	Blacktop / Asphalt	1.20
		*Concrete	1.50
Frost Factor:		**Pipe Size:**	
Heating Degree days:		2" diameter and less	1.00
4000 or less	1.00	3" thru 4" diameter	1.75
4001 - 7000	1.15	6" thru 8" diameter	2.50
7001 or more	1.30	10" thru 14" diameter	3.50
		16" or larger diameter	5.00

* Includes brick and cobblestone surfaces

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The amount of work to install pipes is collected in terms of Full Time Equivalent direct labour. This is to reduce the problems associated with the categories of cost to be included (what level of overhead etc). Results are then compared in terms of man hours of direct labour per adjusted length of pipe installed.

There can be no question that the AGA has gone to considerable lengths to make the comparisons meaningful. Despite this care, it is clear from the approximate nature of the multipliers, and the number of them, that there is significant room for imprecision.

If at the end of the analysis, one can say with confidence that the normalised numbers are comparable within plus or minus 20%, that is that a result anywhere between 80 and 120 for one company is equivalent to a result of 100 in another, then that is excellent analysis. Anyone who thinks they can do better than this is deluding themselves. Comparisons based on processes less rigorous than the AGA process are likely to be much less precise. There is no evidence that Australian regulators approach the task with anywhere near that degree of rigour.

In terms of applying benchmarking in Australia there has been a strong inclination on the part of regulators to look to the performance of utilities overseas (principally US and UK) as representing 'best practice'. The use of international information introduces further significant uncertainties because of the additional requirement to normalise data for currency, and cultural/jurisdictional differences.

Reliance by regulators on highly uncertain benchmarking results exposes service providers to significant risk.

Incentive regulation to reveal 'efficient' costs

The NECG submission suggests that, to remove the uncertainty and consequent cost that arises if regulators are required to estimate 'efficient' costs, those costs be revealed through the operation of incentive regulation. It is probable that policy makers and regulators believe that we have incentive regulation today. In the following I would like to comment on the incentive properties in today's regulatory systems, and the properties necessary to reveal 'efficient' costs and stimulate dynamic efficiency.

The most common approach to incentive regulation employs some form of price or revenue cap which is set for a fixed regulatory period, often about five years. Since prices are set for the period, any improvement in productivity which reduces the average cost of providing the service will result in additional profit to the firm. Hence the incentive to improve productivity. The future benefits from past productivity improvements are then transferred to consumers, either by way of a P_0 adjustment, or by way of a glide-path.

The rationale for incentive regulation is that the lure of improved profits will stimulate service providers to generate efficiency improvements which might otherwise not be realised. The outcome of effective incentive regulation is a continuous journey towards 'efficient' costs. It is in this sense that incentive regulation can be utilised to 'reveal' efficient costs, and be employed instead of regulator assessments which, because of informational uncertainties, can give rise to mistakes, and therefore do give rise to risk.

In the NECG submission the UK and the US approaches to price cap regulation are discussed with reference to Vogelsang's depiction of the key differences between them. In particular, the UK approach attempts to determine X (in CPI-X) so that the resulting price path provides for the continuous transfer of regulator assessments of efficiency benefits to users. This is achieved by determining a price path designed to give the service provider the opportunity to recover regulator assessments of efficient costs and efficient growth over the forthcoming regulatory period.

This is the approach used in Australia. It is designed so that, if the regulator assessments of future improvements in efficiency prove correct, the service provider will not share in them but just earn a return commensurate with risk. The clear objective of this approach is that the service provider should not benefit from improvements in efficiency – anticipated or yet-to-be-achieved efficiency gains are transferred immediately to consumers. That this is so is evidenced by the view which seems to represent current wisdom -- that if the service provider actually earns more than the cost of capital then the regulator has failed, he has set the price cap too loosely. (Another, related issue, which compounds this inequity is that the return is routinely set on an average basis whereas 'efficient costs' are often set at a level which is consistent with above average performance. Thus, if the regulated utility succeeds in controlling costs at the regulator-set level, the return would be just average. This can be compared with the situation in a competitive market where superior performance is generally rewarded by superior returns.)

We make three observations regarding the current regulatory approach:
- because regulator assessments of 'efficient' costs are imprecise this approach is high risk for investors;
- if regulators could accurately forecast 'efficient' costs, service providers would never reap any incentive payments, and the approach becomes rate of return regulation;
- a scheme which is designed to deny any reward when the desired behaviour is delivered cannot be an 'incentive mechanism'. We all know that the best way to get a dog to change its ways is to reward it with something special when it exhibits the desired behaviour – simply relying on 'normal sustenance' of a daily bowl of Chum or worse, threatening to give him less than normal rations if he doesn't perform, wont work.

If we are to employ incentive based regulation we need regulators – and the community, including consumers – to feel OK when service providers actually earn better than their cost of capital. Rather than regulators feeling they have failed, that they have set the bar too low, they should be shouting from the rooftops, "the system is working, A's better than expected profit is evidence that it has produced efficiency improvements. Those efficiency improvements provide the foundation for lower prices in future. Well done A".

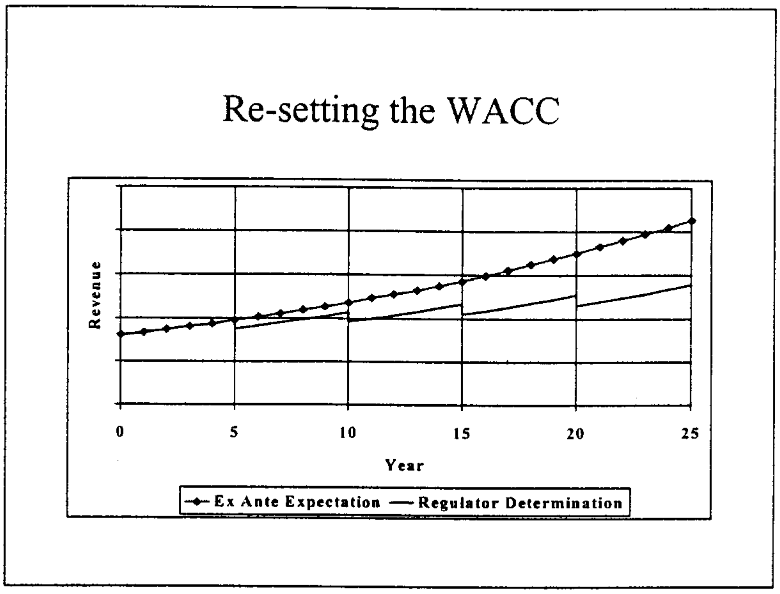
The NECG submission provides an example of an incentive based regulatory system which relies on incentives to reveal 'efficient' costs, and it provides real opportunity for a service provider to earn superior returns from improved efficiency.

Regulatory Cost of capital.

Under current regimes, the cost of capital that will be assumed by regulators in determining regulated prices for access is not known by investors at the time investments are made and is only revealed subsequently through regulatory processes (access reviews or arbitrations). Infrastructure owners must factor this uncertainty into the cost of capital used in investment decision making. The increased cost of capital is likely to rule out some investments which would otherwise have proceeded.

We note that there is precedent for the pre-investment disclosure of the regulatory cost of capital – in regulation of gas before 1990, and in the Petroleum Resource Rent Tax, for example -- and we suggest that economic efficiency would be better served if today's regulatory systems required such disclosure.

Assuming that the initial regulatory cost of capital is made known pre-investment, the question then arises as to what cost of capital will apply at subsequent resets of regulatory prices. While we have limited experience to date, the experience we have suggests that regulators are likely to redetermine the cost of capital based on conditions which apply at the time the reset is determined. This makes sense in relation to certain terms of the cost of capital, for example the risk free rate, but is questionable if the component of risk, beta, is adjusted at periodical resets to reflect the forward looking project risk at the time. The consequence of such a practice is that the revenue on successful projects is likely to be less than is necessary to cover the cost of capital on which the investment decision was based. This is illustrated in the figure below.



Investments are evaluated on the basis of the risk that exists at the time investments are made. This is reflected in project evaluation, whereby a project is deemed successful if over its life it realises a return equal to or in excess of the cost of capital at the time the investment was made. If it is known pre-investment that future prices for successful investments will be determined on the basis of assessments of beta risk at each reset, investors will inevitably take this into account in their investment decisions. The consequence will be that some investments that would otherwise have been undertaken will not proceed.

To overcome this, we suggest that it should be a requirement that the risk component of the cost of capital used to determine access prices be fixed for the life of the investment.

Risky Projects.

The Commission noted that there is a strong 'in principle' case for providing investments in essential infrastructure that are expected to be only marginally profitable with some immunity from exposure to access regulation, and discussed the implementation of 'access holidays' as one possible countermeasure to such undesirable outcomes. It has suggested that access holidays could be implemented through a form of 'null undertaking' that specifies no regulated access would be provided to the service in question for a designated period.

In addition to access holidays, we would ask the Commission to consider the scope for the introduction of a number of mechanisms that address directly the specific issues that are raised by greenfields investments and other investments that are particularly risky. Some risky investments will be successful, but others are likely to fail. Regulation becomes an issue when returns for successful projects are truncated by regulation at the cost of capital for the project (because no symmetric regulatory action can or does turn failed projects into successes). Successful projects need to return more than the cost of capital to offset the losses associated with projects that are not so successful so that, for the industry as a whole, all projects of comparable risk return the cost of capital.

Regulatory mechanisms employed thus far to manage particularly risky investments fail to address the real issues. For example, in the case of the Central West pipeline, a higher cost of capital was assumed by the ACCC (for price determination) and a longer period between regulatory resets (10 years) was offered to address the issues outlined above. However, the reality is that the viability of this project depends on significant regional growth (even if all the existing potential market connected to gas today the project would fail) and the market determines the prices that can be charged. The project will not recover over the next 10 years anywhere near the amount that would be allowed through normal regulatory processes. In other words, there is no need for regulation of this project in the foreseeable future (the market will do that) and the proposed 'extended' regulatory period does nothing to reduce risk.

We do not think an access holiday provides the answer for investors concerned about regulatory risk. Any holiday that would remove the risk that the returns for successful projects may be truncated by regulatory intervention would have to occur towards the end of the project, not at the beginning of the project (when returns are below the cost of capital). Instead, we suggest that the Commission consider the scope for regulated firms to be given some assurance *ex ante* that the additional risks they are bearing will be reflected in regulated access prices. Two potential approaches for the Commission to consider are the Petroleum Resource Rent Tax approach and the pre-investment agreement approach.

The Petroleum Resource Rent Tax (PRRT) approach

The PRRT applies to offshore petroleum exploration and production. Under this approach, a RRT is not imposed until such time as the net present value ('NPV') of the project, discounted by a factor equal to the relevant cost of capital, is positive. The discount rate (or cost of capital) employed in PRRT is the Commonwealth Long Term Bond Rate (LTBR) + 15 per cent for exploration expenditure, and the LTBR + 5 per cent for other expenditures. Once the project is NPV positive, the PRRT is levied at 40 per cent.

We suggest that the same approach could be applied to greenfields investments.[3] Price regulation would not apply until the NPV of the greenfields project, discounted by a factor equal to the relevant cost of capital, is positive. If the project becomes NPV positive then the sharing of benefits would be 60 per cent to owners and 40 per cent to users. This approach would ensure that returns on successful projects would not be truncated at the cost of capital, thereby allowing some 'blue-sky' to offset the losses on projects that are not so successful. This would provide a more favourable environment for entrepreneurial investments.

The pre-investment agreement approach

In addition, we suggest that procedures could be introduced to allow the investor to obtain increased levels of certainty prior to the investment being made on how access prices will be determined.

One option for investors who require greater certainty *ex ante* would be a requirement for an explicit regulatory contract between the regulator and the regulated firm. The terms of this contract would be agreed upon prior to the regulated firm making an investment in assets that

[3] While exploration is more risky than most greenfields infrastructure projects, they do share the common elements of discrete investments with high risk.

are likely to be subject to regulated access requirements under Part IIIA. Such *ex ante* agreements will allow the regulated firm to undertake more precise financial modelling with a view to making the final decision on whether or not to proceed with the investment.