PROPOSED REGULATORY MODEL

FOR THE

DAMPIER TO BUNBURY NATURAL GAS PIPELINE

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Prepared for

Epic Energy

by

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About the Authors

The Brattle Group is an economic, management and environmental consultancy with offices in the United States and the United Kingdom. The firm assesses the economic implications of regulatory proposals, analyses competition, and estimates the value of businesses. Its expertise is focused upon complex, capital-intensive industries such as energy, telecommunications, and transportation. Engagements often include the presentation of formal reports or expert witness testimony before courts and government agencies. The Brattle Group has presented economic analyses to regulatory agencies in Australia, Canada, Denmark, Germany, Hungary, the Netherlands, New Zealand, the United Kingdom, and the United States.

Dr. Carpenter and Mr. Lapuerta have analysed alternative regulatory models for natural gas pipelines in different countries. In the United Kingdom, they testified before the Monopolies and Mergers Commission on the appropriate valuation of the British Gas Pipeline Network for regulatory purposes. They have also submitted comments to the industry regulator, *Ofgas,* analysing the economic incentives of natural gas regulation in the United Kingdom. They have examined alternative regulatory models for natural gas pipelines in the United States, providing written comments on behalf of clients to the Federal Energy Regulatory Commission. They have also consulted to the Australian Competition and Consumer Commission on the privatisation of the Victorian natural gas industry. Dr. Carpenter has a Ph.D. in Applied Economics and a Master’s degree in management from the Massachusetts Institute of Technology, and a degree in Economics from Stanford University. Mr. Lapuerta has degrees in Law and Economics from Harvard University.

Executive Summary

Epic Energy ("Epic") paid Western Australia $2.407 billion for the Dampier to Bunbury Natural Gas Pipeline ("DBNGP"). Epic's bid specified an initial reference tariff of $1/GJ, with subsequent annual price increases no greater than 2/3 of the CPI.[1] Epic has asked us to develop a regulatory model for the DBNGP that would provide the opportunity to earn a fair return on investment while respecting the tariff specified in its bid.

Our regulatory model includes proposals for the initial regulatory asset base, depreciation, the treatment of capital additions, and an accommodation for existing long-term contracts. The key building block of our proposal is an initial tariff of $1/GJ, with annual price increases at 2/3 of the CPI. The initial regulatory asset base would be the purchase price of $2.407 billion, with adjustments for the capital recovery that Epic will have received prior to Jan 1, 2000 and excluding the net present value of existing long-term contracts. Future capital additions, if prudent, will be added to the regulatory asset base at cost.

In the early years of the regime, the operating cash flow implied by the $1/GJ tariff path will likely provide *less* than a fair return on the regulatory asset base as determined by reference to the allowed cost of capital. We propose that the shortfall be "rolled-over" into a "Deferred Recovery Account." If expected volume increases materialise in future years, then this account would be depreciated, providing for full capital recovery. In effect, depreciation of the account is *defined* as the excess of operating income (revenue less operating costs) over the sum of a fair return on the regulatory asset base and depreciation of the physical asset account. In early years this depreciation is negative and the account increases in value, while in later years it should turn positive, allowing the account to shrink until it reaches zero. Epic would be "at risk" for the recovery of this Deferred Recovery Account over the lifetime of the pipeline.

Our proposal effectively commits Epic to the $1/GJ tariff path, preventing any "rate shock" that may be associated with future capital additions. At the same time, our proposal enables real tariffs to fall by even *more* than implied by 2/3 of the CPI, if it becomes evident that current tariff trajectories will permit the full depreciation of the regulatory asset base. Epic will continue to bear the risk that forecast volume increases may not materialise, leading to incomplete recovery of its investment.

Our proposal is consistent with the Gas Pipelines Access (Western Australia) Act 1998 ("GPAA"), which calls for the consideration of the price paid by investors and international practice. It is supported by regulatory practice in Australia, the United States and the United Kingdom. The ACCC and the ORG have both recently accepted the use of

[1] The $1/GJ price refers specifically to the "Standard Forward Haul Firm Tariff" as described in Schedule 39 of the Asset Sale Agreement, p. 3 (i.e., the tariff applies to firm (T1-equivalent) capacity, with receipt at a point upstream of Compressor Station 1 and delivery at Kwinana Junction, and a 100% load factor). All references in this paper to the "price" or "tariff" should be taken to refer to this Standard Forward Haul Firm Tariff, unless otherwise specified.

similar methodologies to capitalise capital under-recovery from gas pipelines or distribution networks. In the United States, a “deferred recovery rate” analogous to the depreciation of our Deferred Recovery Account has been approved by the Federal Energy Regulatory Commission (FERC). In the United Kingdom, the regulatory asset base for several industries has been determined by reference to the price that investors paid the government for privatised assets.

Our proposal strikes a balance between consumers and investors. It allows Epic to expect no more than a fair return on its purchase price and the allowed costs of subsequent investments. At the same time, our proposal ensures that consumers will pay in present value terms no more than the government’s receipts from the sale of the DBNGP, plus operating costs and the allowed costs of future capital additions. The Deferred Recovery Account gives Epic the *opportunity* to recover its investment over the life of the assets, but leaves it bearing the risk that it will fail. Note however that unlike investors in fully competitive markets, Epic is limited to recovering no more than the present value of its investment.

Finally, we explain why alternative regulatory models which value the DBNGP significantly below its purchase price could imply *asymmetric risk* for Epic and for future investors in regulated assets in WA. Such a precedent would unfairly penalise Epic’s investors and could have an undesirable chilling effect on future investment in WA infrastructure.

The Proposal

We have been asked by Epic Energy to propose a regulatory model for the DBNGP beginning in the year 2000. Epic requested that the regulatory model be designed to meet the following objectives:

1. Consistency with Epic's commitment to an initial reference tariff of $1/GJ in 2000, with annual increases limited to at most 2/3 of annual inflation (CPI).

2. Enabling Epic to earn a fair return on its investment in the DBNGP.

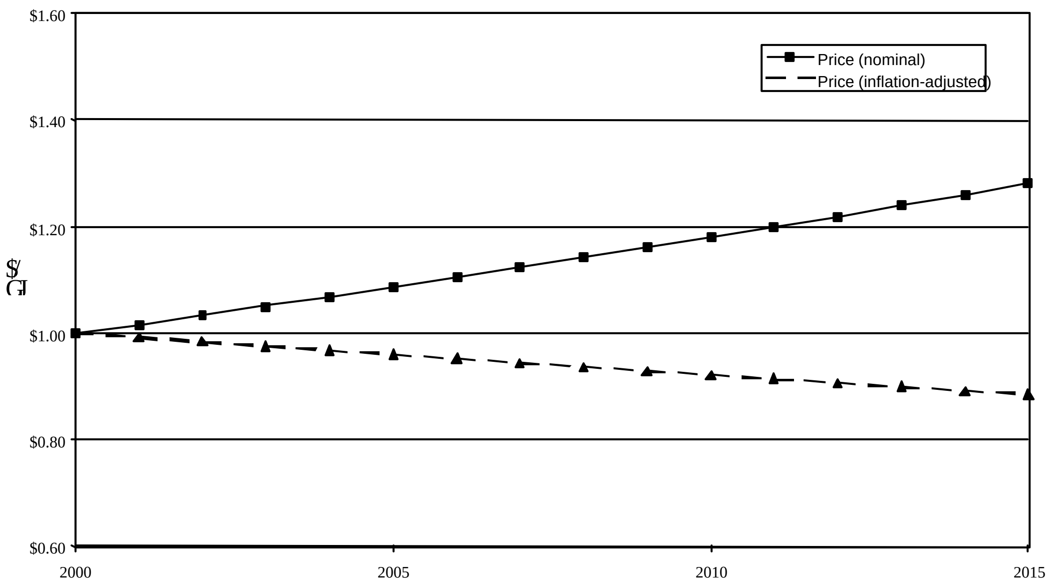
3. Consistency with the economic and regulatory principles embodied in the Gas Pipelines Access (Western Australia) Act 1998.

4. Consistency with broad economic and regulatory principles as applied in regulatory proceedings elsewhere in Australia and internationally.

Our proposed regulatory model incorporates the $1/GJ reference tariff specified in Epic's winning bid for the DBNGP. It also provides a detailed methodology for determining future tariffs. Under this methodology, future prices can never exceed those implied by the 2/3 of CPI price increase limit. Real price decreases may be even greater however, to prevent any capital recovery in excess of the initial purchase price.

Figure 1 below shows the time-path of our proposed tariff (assuming that the price increase cap of 2/3 of CPI binds during the period in question). Below we outline the proposal in greater detail.

Figure 1: DBNGP Reference Tariff ($/GJ)



Initial Reference Tariff

Under our proposal, the reference tariff would be set at $1.00/GJ starting on 1 January 2000. Other tariffs (for part-haul, back haul and delivery beyond Kwinana Junction, and for interruptible service) would be derived from the reference tariff along the lines laid out in the asset sale agreement.[2] Tariff increases in future years would be capped at 2/3 of the CPI, giving real price reductions annually. As explained below, we anticipate that in early years this cap will be binding (i.e, that price increases will equal 2/3 of CPI), but that in later years there may be scope for even greater price reductions.

Initial Regulatory Asset Base

Under our proposal the initial regulatory asset base ("RAB") would be the purchase price of $2.407 billion, less adjustments arising from the transitional period between the date of purchase and the introduction of the new regulatory regime, and from the special status of the "exempt" contract with Alcoa. The adjustments involve subtracting from the initial purchase price: (1) the NPV of actual capital recovery that Epic will receive in the transition period (from all contracts other than the "exempt" Alcoa contract);[3] (2) the NPV of projected future capital recovery from the "exempt" Alcoa contract. As of the purchase date (March 1998), the initial RAB is therefore given by:

Initial RAB = Purchase price –
NPV (capital recovery during transition period) –
NPV (capital recovery from Alcoa exempt contract)

This figure is then grossed up at the Weighted Average Cost of Capital to take into account the time between purchase and the beginning of the new regulatory regime. The methodology is illustrated in Table 1 below. From the initial purchase price in March 1998 of $2,407 (line [1]) we subtract the NPV of capital recovery from the Alcoa exempt contract (line [2]) and the NPV of capital recovery during the transition period (line [3]) to get an adjusted figure of $1,707 (line [5]). The $1,707 is then grossed up at the Weighted Average Cost of Capital to give a value at the beginning of 2000 of $2,098 (line [6]).

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[2] See Sale Agreement, Schedule 39 ("Buyer's Proposed Tariff Rates and Path").

[3] Capital recovery is defined as revenue less operating costs. Operating costs are defined in economic terms (*i.e.*, based on true incremental costs), and may differ from costs as defined in the Alcoa contract.

Table 1: Illustration of Determination of Initial Asset Base

			1998	1999	2000
Purchase Price (March 1998)	[1]		$2,407		
NPV of Exempt Contract (March 1998)	[2]	*Assumed*	$500		
NPV of Capital Recovery in Transition Period (March 1998)	[3]	*Assumed*	$200		
Total Adjustment to Purchase Price (March 1998)	[4]	[2]+[3]	$700		
Adjusted Purchase Price (March 1998)	[5]	[1]-[4]	$1,707		
Total Rate Base (BOY 2000)	[6]				$2,098

Note:

[2], [3]: NPV's are measured as of March 1998. They should be calculated based on future revenues, as expected at time of purchase. Figures shown are purely illustrative.

[3]: excluding recovery from the exempt contract.

[6]: equals [5] x (1+WACC)^1.75. We use a WACC of 12.5%, taken from a Brattle Group study of the cost of capital for the DBNGP. The 1.75 represents the time (in years) between the purchase in March 1998 and the beginning of the new regulatory regime in January 2000.

Capital Additions

Our proposal follows standard regulatory practice in its treatment of capital additions. They are added to the regulatory asset base at cost, provided they are deemed prudent by the regulator. The prudency test covers both the prudence of the investment *per se*, and the price paid for the new assets. If an investment is deemed imprudent, then the regulator determines how much of its cost, if any, should be added to the rate base.[4]

Depreciation

We anticipate that in the early years of the regime, the chosen reference tariff will be insufficient to cover the cost of capital on the regulatory asset base defined above. Under our proposal, the shortfall is treated as "negative depreciation" or "rolled over" into a "Deferred Recovery Account." This Deferred Recovery Account forms part of the rate base, which is treated as the sum of two such "accounts": the Deferred Recovery Account and the Physical Asset Account. The latter account represents the initial value of the asset base, and is itself subject to depreciation in the standard way (as well as augmentation by prudent capital investments).

The initial value of the Physical Asset Account is set equal to the initial regulatory base, as discussed above. The initial value of the Deferred Recovery Account is set to zero. We expect the Deferred Recovery Account to increase in value in the first few years, due to the roll-over/negative depreciation. We allow for the fact that in later years higher volumes may allow for full recovery of the required return, in which case the account will be fully depreciated over time. After it has been fully depreciated, it may become possible to start reducing prices faster than implied by the 2/3 of CPI growth

[4] However, we note that hindsight prudence reviews present a form of "asymmetric risk," an issue we discuss below.

cap.[5] However, Epic continues to bear the risk that future volume increases will be insufficient ever to fully depreciate the account (see our later discussion in relation to section 8.33 (b) of the GPAA).

Table 2 below provides a more detailed illustration of the depreciation methodology.[6] Looking, for example, at the year 2000, the total rate base has a value of $2,098 (line [9]) at the beginning of the year. This gives total allowed capital charges of $288 (line [13]).[7] However, actual operating income is only $82 (line [22]). The shortfall of $288 - $82 = $206 is deemed to be "negative depreciation" (line [16]). It is applied to the Deferred Recovery Account, which therefore increases from $0 at the beginning of 2000 to $206 at the end of 2000 (line [18]).[8]

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[5] However, if Epic were to undertake future major capital additions, then deferred recovery might arise again, if the $1/GJ tariff path were insufficient to allow capital recovery in the early years of the expansion. In that case we would again see negative depreciation of the Deferred Recovery Account, until greater utilisation of the expanded capacity in later years allowed for full recovery.

[6] Table 2 is provided for illustrative purposes only, and does not purport to provide a full and accurate valuation of the DBNGP. It uses a pre-tax nominal Weighted Average Cost of Capital (WACC).

[7] Calculated as the sum of depreciation of the physical asset rate base ($18, in line [12]) and a 12.5% (line [10]) allowed return on the total rate base of $2,258 (line [9]): $18 + 12.5% x $2,258 = $300.

[8] Strictly speaking, the depreciation of -$218 is subtracted from the Beginning of Year value of $0 to give an End of Year value of +$218.

Table 2: Illustration of Proposed Regulatory Accounting Methodology

			1998	1999	2000	2001	2002	2003	2004	2005
RATE BASE										
Initial Rate Base										
Purchase Price (March 1998)	[1]		$2,407							
After-tax NPV of Exempt Contract (March 1998)	[2]	*Assumed*	$500							
NPV of Capital Recovery in Transition Period (March 1998)	[3]	*Assumed*	$200							
Total Adjustment to Purchase Price (March 1998)	[4]	[2]+[3]	$700							
Adjusted Purchase Price (March 1998)	[5]	[1]-[4]	$1,707							
Total Rate Base (BOY 2000)	[6]	[5]x(1+[10])^1.75			$2,098					
Beginning of Year Rate Base										
Physical Asset Account (BOY)	[7]	*See Note*			$2,098	$2,178	$2,258	$2,338	$2,418	$2,498
Deferred Recovery Account (BOY)	[8]	*See Note*			$0	$206	$441	$713	$1,026	$1,385
Total Rate Base (BOY)	[9]	[7]+[8]			$2,098	$2,384	$2,699	$3,051	$3,444	$3,883
Allowed Return on Capital										
Pre-tax nominal WACC	[10]	*See Note*	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%	12.5%
Allowed pre-tax return on capital	[11]	[10]x[9]			$262	$298	$337	$381	$431	$485
Allowed Depreciation Charges										
Depreciation of Physical Asset Rate Base	[12]	*See Note*			$26	$26	$26	$26	$26	$26
Total Allowed Capital Charges										
Total Allowed Capital Charges	[13]	[11]+[12]			$288	$324	$364	$408	$457	$512
Capital Additions										
Capital Additions	[14]	*See Note*			$106	$106	$106	$106	$106	$106
End of Year Rate Base										
Depreciation of Physical Asset Account	[15]	[12]			$26	$26	$26	$26	$26	$26
Depreciation of Deferred Recovery Account	[16]	[22]-[13]			-$206	-$235	-$272	-$314	-$359	-$417
Physical Asset Account (EOY)	[17]	[7]+[14]-[12]			$2,178	$2,258	$2,338	$2,418	$2,498	$2,578
Deferred Recovery Account (EOY)	[18]	[8]-[16]			$206	$441	$713	$1,026	$1,385	$1,801
Total Rate Base (EOY)	[19]	[17]+[18]			$2,384	$2,699	$3,051	$3,444	$3,883	$4,379
REVENUE										
Revenue	[20]	*See Note*			$134	$143	$146	$149	$154	$152
OPERATING EXPENDITURE										
Total	[21]	*See Note*			$52	$53	$54	$55	$56	$57
OPERATING INCOME										
Operating Income	[22]	[20]-[21]			$82	$90	$92	$94	$98	$95

Notes:
[2], [3]: NPV's are measured as of March 1998. They should be calculated based on future revenues, as expected at time of purchase. Figures shown are purely illustrative.
[3]: excluding recovery from the exempt contract.
[6]: equals [5] x (1+WACC)^1.75. We use a WACC of 12.5%, taken from a Brattle Group study of the cost of capital for the DBNGP. The 1.75 represents the time (in years) between the purchase in March 1998 and the beginning of the new regulatory regime in January 2000.
[7]: equals [6] in year 2000. Thereafter, equals previous [17].
[8]: equals 0 in year 2000. Thereafter, equals previous [18].
[10]: derived from Brattle Group study of cost of capital for DBNGP.
[12]: For illustrative purposes, we assume straightline depreciation of the physical asset base over the economic life of the assets, assumed to be 80 years.
[14]: Assume capital additions of $106mn per year over years 2000-07, none thereafter.
[20], [21]: derived from indicative forecasts, provided for illustrative purposes only.

The same deferred recovery methodology has recently been approved by the ACCC, in a draft access decision concerning the Central West Pipeline (CWP).[9] The pipeline's owner, AGL Pipelines (NSW) Pty Ltd (AGLP), believes that low throughput in its early years, combined with low initial tariffs, will lead to capital under-recovery. They propose to use the methodology described here, defining what they call "economic depreciation" as the difference between operating income (revenues less operating costs) and the return on capital.[10] The ACCC wrote that:[11]

> [a]s a result of low forecast throughput during the early years of the CWP, coupled with low initial tariffs (which are intended to stimulate demand), revenue is not expected to recover all costs during the first phase of the

[9] ACCC, *Access Arrangement by AGL Pipelines (NSW) Pty Ltd for the Central West Pipeline*, Draft Decision, CR99/3, 10 September, 1999.

[10] *Ibid*, p. 15.

[11] *Ibid*, p. 10.

> lifetime of the CWP. AGLP's economic depreciation approach is intended to allow AGLP to subsequently recoup these under-recovered revenues and have the opportunity to earn a revenue stream that covers efficient costs over the life of the asset. *The methodology results in negative depreciation during the first phase, which has the effect of increasing the asset value for regulatory purposes.* [Emphasis added]

Under the proposed methodology, the CWP regulatory asset base is expected to increase from under $30 million in 1999, to over $45 million in 2004.[12]

Two recent decisions by the ORG involved similar approaches to capital under-recovery. In its decision on Envestra Ltd's access arrangement for the Mildura natural gas distribution system, the ORG accepted a proposal from Envestra to deal with under-recovery by "rolling it over" into the assset base, noting that "[t]his under-recovery can be considered, in the terminology of the Code, as being 'an element of negative depreciation' which enables the Reference Tariff to be kept stable over the Access Arrangement period and the life of the asset, and that is consistent with the growth of the market for the Services".[13] The ORG also accepted a similar arrangement in its decision on Eastcoast Gas Ltd's access arrangement for the East Gippsland natural gas distribution system.[14]

Finally, a similar methodology has also previously been approved in the United States by the Federal Energy Regulatory Commission (FERC), in the case of a proposed gas pipeline.[15] The company proposing to build the pipeline, SunShine Interstate Transmission Company (SITCO), anticipated a ramping-up of volumes through its life, such that its revenues in the first few years of operation would be insufficient for capital recovery. SITCO therefore proposed to add an additional rate component over the life of the project, its "Deferred Recovery Rate," to give it an opportunity to recover its full investment once full volumes materialised. SITCO's Deferred Recovery Rate corresponds to our proposed depreciation of the Deferred Recovery Account.

Future Tariffs

We anticipate that increased future usage of the DBNGP will lead to higher revenues, so that the Deferred Recovery Account will start to fall over time. If price increases were to remain at 2/3 of CPI, this might lead to a situation of "excess capital recovery," i.e., where the NPV of profits arising from the pipeline exceeded the asset base. While such a situation could always be remedied by requiring the pipeline to run at a loss for a suitable period of time, there are good administrative and economic reasons to avoid such an

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[12] *Ibid*, p.13.

[13] ORG, *Final Decision in respect of the Envestra Ltd's proposed access arrangement for the Mildura natural gas distribution system*, 3 June 1999, p. 34.

[14] ORG, *Final Decision in respect of the Eastcoast Gas Pty Ltd.'s proposed access arrangement for the East Gippsland natural gas distribution system*, 6 May 1999.

[15] SunShine Interstate Transmission Company, 67 FERC P 61, 229.

outcome. Instead, if it becomes apparent that the current price path risks excess capital recovery, the efficiency factor X could be reduced at a future regulatory review from its current value of 2/3. The new value should be chosen with the aim of ensuring that the regulatory asset base will be fully depreciated, *but no more than fully depreciated*, over the remaining useful life of the pipeline. If necessary, the efficiency factor X can be reset at subsequent regulatory reviews.

Of course, there is no guarantee that the future volumes necessary to recover the regulatory asset value will materialise. We note again that under our proposal Epic would bear the associated "volume risk."

Regulatory Asset Base and the GPAA

Our proposal is consistent with several sections of the GPAA, as shown in Table 3 and discussed below:

Table 3: Our Proposal and the GPAA

Section	Issue	Treatment in our Proposal
8.10 (e)	*International Best Practice*	Follows US precedent in "Deferred Recovery" methodology, and UK regulatory trend in using market value as basis for valuation of newly privatised assets.
8.10 (f)	*Past Tariffs*	Initial reference tariff of $1/GJ is comparable to recent prices ($1.19/GJ in 1998, $1.10/GJ in 1999).
8.10 (j)	*Use of Purchase Price*	Tariff path and valuation based on Epic's winning bid and sale agreement with government of WA.
8.11	*DAC/DORC*	Proposal exceeds DAC/DORC, but exceptions contemplated.
8.16	*Capital Additions*	Capital additions added at cost, provided they meet prudency test.
8.33 (a)	*Efficient Depreciation*	Reference Tariff falls (in real terms) smoothly over time.
8.33 (b)	*Depreciation over Economic Life*	Deferred Recovery Account depreciated over life of DBNGP, Physical Asset Account over life of assets.

§ 8.10 (j): Purchase Price and the Circumstances of Purchase

In determining the appropriate regulatory asset base, Section 8.10 (j) calls for consideration of "the price paid for any asset recently purchased by the Service Provider and the circumstances of that purchase." Our proposal measures the initial regulatory asset base by direct reference to the "price paid for" the pipeline "recently purchased by"

Epic. Our proposal further considers the "circumstances of that purchase" by explicitly adopting the tariff path specified in Epic's successful bid and by using it to calculate regulatory depreciation, which determines the value of the regulatory asset base in the future.

Epic's commitment to the $1/GJ tariff was made explicit in Schedule 39 of the Asset Sale Agreement:[16]

[16] Schedule 39 of the Agreement, p. 3.

> Epic proposes a standard tariff for Forward Haul Firm Transportation Service for all existing contracts and new contracts (excluding Negotiated Contracts such as Alcoa). The proposed Standard Forward Haul Firm Tariff is $1.00/gj … from on [sic] 1 January 2000. Yearly tariff increase are proposed to be limited to 2/3 (67%) of annual inflation (CPI).

A direct connection between the tariff commitment and the purchase price was drawn by Epic's acknowledgement that the proposed tariffs would "provide the Buyer with an acceptable return on investment[.]"[17]

The government's acceptance of this commitment can be inferred from the requirement that each bid specify prospective tariffs, combined with the acceptance of Epic's winning bid. The discussion of tariffs under Schedule 39 was not optional; Epic's bid would have been rejected had it failed to specify a tariff. More importantly, Epic also made a second bid [this information has been deleted. See NOTE at start of Submission].

Table 4: Menu of bids for DBNGP offered

	Bid 1	Bid 2
	[this information has been deleted. See NOTE at start of Submission]	

In economic terms, the bids presented a trade-off to the government between two key objectives: maximising revenues from the privatisation, and achieving lower transmission prices for consumers. By selecting the [this information has been deleted. See NOTE at start of Submission] bid, the government effectively expressed a preference for [this information has been deleted. See NOTE at start of Submission] in revenue from the [this information has been deleted. See NOTE at start of Submission] bid, in exchange for [this information has been deleted. See NOTE at start of Submission] instead of [this information has been deleted. See NOTE at start of Submission]. Although we understand that [this information has been deleted. See NOTE at start of Submission], Epic would not have submitted two different bids unless it believed [this information has been deleted. See NOTE at start of Submission].

A number of statements imply that the government shared this understanding of the asset sale. Energy Minister Colin Barnett recognised in announcing the sale that the government had to balance the goal of a high sale price against that of achieving lower tariffs:[18]

[17] Schedule 5, Part A Buyer's Warranties, clause 9.

[18] Government of WA Ministerial Media Statement, 22/5/97.

> "*It is imperative the Government sells the pipeline to deliver the highest possible return to WA taxpayers* who have owned this asset since it was built in 1984," he said.
>
> "Issues such as *ensuring gas transport costs are kept down*, the desire to increase gas supply to encourage further downstream processing projects, the need to protect long-term supplies and maintain prices for households and small businesses were all key points of consideration the Government had to take into account.
>
> "*These are all valid but not necessarily consistent issues that have been weighed up before the final decision was made. I believe the Government has balanced these competing issues* and come up with an equitable solution." [emphasis added]

More recently, the Minister has acknowledged that the tariff agreed with Epic contributed to the price received for the DBNGP:[19]

> Last year the Dampier-Bunbury natural gas pipeline was sold for $2.4b. That result was important, but it was also a noteworthy example of why it is necessary to resolve policy issues prior to making decisions to sell or privatise assets. In the sale of the Dampier-Bunbury pipeline a number of policy issues were thought out and implemented prior to the sale. *From my perspective that was one of the keys to the success and the achievement of such a high price. Apart from the $2.4b in proceeds, the sale included a reduction in transport tariffs of 18 per cent over three years.* A decision was made to widen the easement from 30 metres to 100 metres to allow future gas pipelines to be constructed,… [emphasis added]

To summarise, our model can be said to reflect the "circumstances of that purchase" by Epic in the sense that Epic specified [this information has been deleted. See NOTE at start of Submission] in its successful bid, the government rejected Epic's alternative bid with [this information has been deleted. See NOTE at start of Submission], and the government had recognised Epic's proposed tariff as contributing to the success of the sale, and as supporting the price received.

§ 8.10 (e): International Best Practice

Section 8.10 (e) of the GPAA mandates consideration of "international best practice of Pipelines in comparable situations." We have already noted the methodological precedent provided by the United States FERC. In addition, our proposal is supported by regulatory practice in the United Kingdom in determining the rate base for recently privatised utilities. The United Kingdom has been on the forefront of privatisation and regulation of network industries. As in the case of the DBNGP, there has frequently been a significant gap in the UK between the price paid for the business at privatisation, and the replacement cost of its infrastructure (although in the UK purchase price has

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[19] Speaking at the Second Reading of the Gas Corporation (Business Disposal) Bill 1999 on 16/9/99 (*Hansard* for 16/9/99, p.1322). The 18% price reduction Mr Barnett mentions presumably refers to the change from the 1998 reference tariff of $1.189/GJ to Epic's proposed 2000 reference tariff of $1/GJ.

frequently been less than replacement cost). In these circumstances, UK regulators have commonly determined the regulatory asset value by reference to the purchase price of the assets, and have added subsequent prudent investments to the rate base at their projected costs.

The regulatory asset value of the British Gas pipeline network was based on its 1991 market value,[20] with subsequent capital additions included at cost. The Monopolies and Mergers Commission approved the use of market value as an appropriate balance between the interests of shareholders and investors.[21]

The same approach has been used for the privatised electricity distribution businesses. In 1994 the UK electricity regulator Professor Stephen Littlechild wrote in his Distribution Price Control proposals:[22]

> It seems to me appropriate to have regard to the money actually paid to purchase a company, not just to the value of assets in the accounts. The valuation of a company at flotation reflected what the original shareholders considered was the likely stream of future dividends, taking into account the information in a very full Prospectus and the risks attached to the investment, and valuing the whole of each company. It would be wrong not to give considerable weight to this.

Consistent with this statement, *Offer* in 1995 determined regulatory asset values for the Regional Electricity Companies' (RECs) distribution businesses based on their market values at the end of the first day's trading.[23] In 1996, *Offer* confronted the issue of an appropriate regulatory value for the National Grid Company, which operates the high-voltage transmission system in England and Wales. Professor Littlechild referred back to its decision concerning the Regional Electricity Companies:[24]

> It seemed to me appropriate to have regard to the money actually paid to purchase a company, that is the original flotation or initial market value, not just to the value of assets in the accounts. *Subsequent experience and regulatory practice has reinforced this view…* Using an approach to asset

[20] The UK's gas industry was initially privatised as a single, vertically integrated business. Following some controversy, the Monopolies and Mergers Commission (MMC) recommended use of the market value at the end of 1991 (around five years after privatisation), allocated over the different British Gas Businesses in proportion to current cost net book value. Office of Gas Regulation, *1997 Price Control Review British Gas' Transportation and Storage: The Director General's final proposals* (August 1996), p. 112.

[21] MMC, British Gas plc: Volume 1 of Reports Under the Gas Act 1986 on the Conveyance and Storage of Gas and the Fixing of Tariffs for the Supply of Gas by British Gas plc (August 1993).

[22] *The Distribution Price Control: Proposals* (August 1994), p. 65.

[23] An adjustment was also made to take into account the value of the UK's transmission business, which was "bundled" with the RECs at privatisation.

[24] *The Transmission Price Control Review of the National Grid Company: Fourth Consultation* (August 1996), ¶¶ 7.16, 7.22 (emphasis added).

> valuation based on the July 1995 REC proposals has value in maintaining regulatory consistency.

The MMC valued Scottish Hydro-Electric's distribution business using as a starting point the average market value for Scottish Hydro-Electric plc over the 100 days after flotation.[25] For Northern Ireland Electricity, Offer NI has used market value at the end of the first day's trading.[26]

Finally, the same approach has also been applied in water regulation in the UK. Regulators have determined the rate base of water utilities as an average market value over the 200 days after flotation.[27]

§ 8.10 (f): Past Tariffs

Section 8.10 (f) requires consideration of "the basis on which Tariffs have been…set in the past." If this language is read as referring to methodology, then the novelty of the DBNGP privatisation in Western Australia precludes any useful precedent. If this language is read as referring to the absolute level of tariffs, then our proposal finds direct support. Our reference tariff of $1/GJ involves real price reductions compared to the present tariff and it is consistent with the transitional tariff price path agreed by the government at the time of sale as the "lowest feasible." Indeed Energy Minister Colin Barnett has stated that:[28]

> [W]hen the Government sold the AlintaGas transmission system, the Dampier to Bunbury natural gas pipeline, it ensured that *the lowest feasible tariffs applied during the transitional period* until tariffs were developed and approved under the National Access Code and independent regulation. [emphasis added]

Our proposal also involves a steady reduction in real tariffs over time, as shown in Figure 1 above.

Finally, the transitional tariffs may also be viewed as a legitimate basis for Epic's expectations as to the asset value of the DBNGP at the time of purchase. Indeed OffGAR makes the same point in its Draft Decision on the Access Arrangement for CMS's Parmelia Pipeline:[29]

> The required information relates to CMS's reasonable expectations of the asset value of the Parmelia Pipeline at the time of purchase. The historical

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[25] See Appendix 7 to Ofgas, *1997 Price Control Review, British Gas' Transportation and Storage: The Director General's Final Proposals* (August 1996).

[26] *Ibid*.

[27] *Ibid*.

[28] Speaking at the Second Reading of the Gas Corporation (Business Disposal) Bill 1999 on 1/7/99 (*Hansard* for 1/7/99, p.9933).

[29] OffGAR, *Draft Decision: Access Arrangement Parmelia Pipeline*, 27 Oct 1999, p. 77.

> basis for the setting of tariffs may have had some bearing on these expectations and thus pertinent to the Regulator's consideration of the Initial Capital Base. (*sic*)

Epic's expectation at the time of purchase, strongly reinforced by the purchase agreement, was that the transitional tariffs provided a sound basis for forecasting future tariffs. To impose tariffs significantly below Epic's proposal, which itself involves real reductions relative to the transitional tariffs, would therefore be inconsistent with the expectations that reasonably arose from past tariffs.

§ 8.11: Historic Cost and Replacement Cost

Section 8.11 of the GPAA states that "[t]he initial Capital Base…normally should not fall outside the range of values" determined by the depreciated historic cost and replacement cost of the underlying assets. The rate base in our proposal would appear to exceed this range. However, we note that the phrase "*normally* should not fall outside" clearly contemplates exceptions. Section 8.10 goes further, by suggesting numerous factors other than historic and replacement cost valuations.

In our view, the circumstances surrounding the sale of the DBNGP to Epic are sufficient to warrant a departure from the use of either historic or replacement costs in determining the regulatory asset base. A key factor here is the linkage between the price paid for the pipeline and [this information has been deleted. See NOTE at start of Submission]. Our model also does not guarantee that Epic will recover its full purchase price, but it does give it an *opportunity* to do so.

§ 8.16: Capital Additions

Section 8.16 requires that capital additions be included in the regulatory asset base at their actual costs, providing they are prudently incurred. Our proposal implements this provision.

§ 8.33 (a): Efficient Depreciation

Section 8.33 of the GPAA places certain requirements on the regulatory depreciation schedule. Our proposal in fact combines two such schedules, one for the Physical Asset Account and another for the Deferred Recovery Account. Depreciation of the Physical Asset Account follows standard lines, while the Deferred Recovery Account is depreciated in the manner outlined above. Both schedules are consistent with the relevant provisions of the GPAA.

Section 8.33 (a) seeks a depreciation schedule that produces tariffs "changing over time in a manner that is consistent with the efficient growth of the market for the Services provided by the Pipeline." For the Physical Asset Account, a number of standard depreciation methodologies are available that are likely to be consistent with this requirement. In Table 2 above we apply straightline depreciation to the Physical Asset Account.

Our depreciation schedule for the Deferred Recovery Account is derived implicitly from tariffs that have an efficient time profile. Relative to traditional schedules, the schedule effectively postpones capital recovery until higher future volumes materialise. The higher volumes then allow Epic to receive higher revenues and recover capital without requiring an increase in the *absolute* level of prices. By contrast, traditional depreciation schedules in conjunction with the same regulatory asset base would produce extremely high prices over the next few years, and lower prices in the future. Our proposal is efficient because it produces stable and predictable prices that more closely parallel competitive markets, where equilibrium prices are steady in real terms per unit of volume.

Section 8.33 (b): Depreciation over Economic Life of Asset

Section 8.33 (b) requires that "each asset…is depreciated over the economic life of that asset[.]" Again, we note that both the depreciation schedule applied to the Physical Asset Account and that applied to the Deferred Recovery Account satisfy this requirement.

For the physical assets this is straightforward. In Table 2 above the pipeline is treated as a single asset, with straightline depreciation over its economic life. However, a conceptually more difficult question arises in relation to depreciation of the Deferred Recovery Account. We propose that its economic life be viewed as the life of the DBNGP itself. If at the end of that time, which presumably will coincide with exhaustion of the gas fields it serves, the Deferred Recovery Account has not been fully depreciated then it should be viewed as representing an imprudent investment, and written down to zero without compensation. Epic will therefore continue to bear the "volume risk" associated with the DBNGP, since if forecast volume increases fail to materialise it will be unable to fully recover its capital investment.

This approach is consistent not only with 8.33 (b) but also with the FERC's practice in the SITCO case discussed above. The FERC commented that:[30]

> It is important to note, however, that this rate device [the Deferred Recovery Rate] does not completely relieve SITCO of the risk of underutilisation. Since the deferred recovery costs will be spread throughout the project's 25-year life, SITCO will be made whole for the shortfalls only if it is able to market its projected service levels both during and after the build-up.

Imposing volume risk on Epic is also consistent with OffGAR's draft decision concerning the Parmelia pipeline. OffGAR apparently projected Parmelia's existing tariffs into the future under different volume growth assumptions and discounted the resulting cash flows to their present value under the "ODV" approach. This procedure would explain the statement that $62.5 million "allows for expectations of market growth to be reflected in the asset value."[31] Apparently, the volume projections that were applied

[30] FERC cited at note 15, p.13.

[31] *Supra,* Note 29 at Part A-10.

to existing tariffs in deriving an ODV value involved an assumption of market growth. OffGAR also cautioned:[32]

> However, this value will only be accepted by the Regulator if the Access Arrangement is amended to include a Redundant Capital Policy that provides for the Capital Base to be reduced at the end of the Access Arrangement Period if expectations of market growth are not realised.

OffGAR was apparently concerned that, if anticipated volume growth did not materialise, that the resulting rates per unit of throughput would either increase above existing levels, or fail to decrease as anticipated. By asking for a Redundant Capital Policy, OffGAR effectively made the full recovery of the asset base contingent on future demand levels, placing the pipeline owners at risk to safeguard a desired tariff path. Our proposal effectively addresses such concerns. Our proposal imposes volume risk upon Epic and automatically safeguards the tariff path implicit in its winning bid.

Our proposal is in several ways superior to the Parmelia proposal. Because the Parmelia proposal uses a "bottom-up" approach to derive rates from an asset base, it does not ensure that tariffs will precisely follow any desired path in the future. Although the Redundant Capital Policy preserves OffGAR's discretion to reduce the capital base if rates threaten to become excessive, there is no up-front guarantee to keep rates at specific levels. The regulator can expect future antagonism over precisely *when* the rates become excessive, and disputes whether future volume growth is forever unlikely or just on the horizon. Our proposal, by contrast, commits directly to a tariff path and derives the depreciation figure implicitly from that path, avoiding the prospect of future antagonism. OffGAR is guaranteed that prices will not exceed the tariff path initially contemplated, and also retains the ability to force tariffs *even lower,* if it ever appears that the $1 path will provide more than the necessary returns to compensate Epic fully for its purchase price.

[32] *Ibid,* Part A-11.

Other Regulatory Principles

In designing our proposal, we have sought to achieve consistency not only with the GPAA but also with the broad principles that underlie regulatory practice in various jurisdictions. Two of those principles are of particular relevance to our proposal. First, we explain below why our proposal strikes a reasonable balance between the interest of consumers and shareholders. Second, we expand on a topic already mentioned above, the issue of “asymmetric risk.” We explain why the use in this instance of a valuation based on historic or replacement cost might conflict with best regulatory practice, by creating a precedent of exposing purchasers of privatised regulated assets to a negative risk with no corresponding upside.

Balance Between Consumers and Shareholders

One regulatory principle is to strike an appropriate balance between the interests of ratepayers and shareholders. Although economics does not provide a unique solution to the appropriate balance, we should point out that several economic aspects of our proposal may appeal to notions of fairness.

First, the return received by Epic’s shareholders is at most a “fair return,” in the economic sense. It is the return that it could expect to achieve in a competitive market, or equivalently, the return that its shareholders could earn by investing in alternative assets of equivalent risk. Epic’s shareholders may get less than this fair return if the anticipated volume increases fail to materialise, but will not get more should unanticipated volume increases occur.[33] From an economic point of view, the implicit principle is that investors in a natural monopoly should neither suffer a penalty nor enjoy a reward for investing in such an industry rather than a competitive one.

A second, economically-equivalent formulation is to note that the total expected return to Epic from its purchase of the DBNGP, appropriately measured (i.e., in terms of the net present value of capital charges discounted at the cost of capital), exactly matches the initial purchase price paid to the government.[34] Again, the proposal provides no opportunity for Epic to enjoy an excess or undue profit from the transaction.

Third and perhaps most important, the proposal places no undue burden on consumers in WA. The present value of rates paid by those consumers over the lifetime of the pipeline would at most exactly match the proceeds received by the government at

[33] As with all “performance based regulation” (PBR) Epic will be able to earn a return consistently higher than the “fair” return only if it is able continually to produce innovations in efficiency. Under PBR the benefits of such innovations accrue in the long-run to consumers via price reductions.

[34] We also understand that independent of NPV considerations the $1/GJ initial tariff was considered necessary by the pipeline’s bankers to ensure sufficient cashflow in the pipeline’s early years to finance the $2.4bn purchase.

privatisation.[35] Those proceeds in turn will provide a continuing stream of community benefits. Energy Minister Colin Barnett noted that[36]

> We retired a significant part of direct and general government debt out of the sale of the Dampier-Bunbury natural gas pipeline…[in addition] two broader community benefits were achieved. A total of $100m was put into computers, technology and schools. We put 26,000 computers into government schools over four years and 6,000 computers into non-government schools. In a sense, *the pipeline was a community-owned asset and the distribution of the proceeds went to everyone*, both government and non-government schoolchildren. That program has very strong community support and is producing substantial educational benefits. It was decided to allocate $100m to the development of a convention centre for Perth…Such a facility is important to attract conferences and activities to Perth the benefits of which will then feed into our regional areas. [emphasis added]

In sum, our proposal provides for a fair balance between shareholders and ratepayers, ensuring that the present value of future tariffs will not exceed the value that accrued to the state and its citizens through the purchase price.

Asymmetric Risk

A further advantage of our proposal is that, as we explain below, it protects Epic from being harmed by some (though not all) forms of "asymmetric risk." Asymmetric risk arises when the possibility that investors will realise a bad outcome is not balanced by a similar opportunity for gain. As such, asymmetric risk can only occur in regulated markets, because prices in unregulated markets prices adjust so that investors can expect to earn their cost of capital on average, over the range of possible outcomes. Thus, hotels in hurricane-prone regions will price rooms so that their earnings in periods without hurricanes compensate them for the capital loss that arises when hurricanes do hit (or for an insurance premium to protect against such a loss). In periods without hurricanes, hotel investors will expect to earn a return above their cost of capital (or to recover the necessary insurance premium in all periods on average). If regulation is not designed appropriately, however, the risk of some losses may not be balanced by offsetting opportunities for gains, and no "insurance" is available to purchase as a protection. As a result, investors in these firms cannot expect to earn their cost of capital on average. Asymmetric risk can produce long-term inefficiency by inhibiting investors from making appropriate investments.

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[35] More accurately, the present value of the portion of those rates that corresponds to a fair or market rent for the assets would exactly equal the proceeds received by the government in return for transfer of the assets at privatisation.

[36] Speaking at the Second Reading of the Gas Corporation (Business Disposal) Bill 1999 on 16/9/99 (*Hansard* for 16/9/99, p.1327).

Regulatory Precedent

The importance of avoiding asymmetric risk is widely recognised internationally, and has been the subject of numerous articles in academic and practitioner journals and texts.[37] The United States Federal Energy Regulatory Commission (FERC) in 1979 described the concept, distinguishing asymmetric risks from those that present the regulated company with both upside and downside risk:[38]

> Risk for gas pipelines in general is the result of certain events that may cause actual or realised rates of return to deviate from the rate of return allowed by the Commission…A categorisation of risks is, in effect, a categorisation of those events that could cause rates of return to fluctuate.
>
> Broadly speaking, the first…category of events are those that would cause the realised rate of return to fall below the allowed rate. For example, suppose the possibility of Event A occurring in any one year…is 10 percent. Suppose also that if Event A does occur, the realised rate of return for that year will be reduced by three percentage points…from the allowed rate...In order to provide minimum compensation for the risk of Event A occurring, the Commission should increase the allowed rate…by 0.3 percentage points...
>
> The second category of risky events are those events which are just as likely to increase the realised rate of return as to lower it. Such an event creates general uncertainty about the realised rate but does not bias the realised rate either down or up.

In the United States, a number of decisions by state and federal regulators have explicitly recognised the need to prevent or compensate for exposure to asymmetric risk. For example, in the 1979 decision cited above, the Federal Energy Regulatory Commission (FERC) provided compensation for asymmetric risk attached to the Alaska Natural Gas Transportation System, by making a one-off adjustment to the rate base.[39] The California Public Utilities Commission (PUC) in 1989 granted local telephone companies an asymmetric risk premium above the cost of capital to offset an asymmetric feature of the prevailing incentive rate mechanism.[40] In 1996, the Hawaii PUC shielded the local electric utility, Citizens Utilities Companies (Kauai Electric Division), from the

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[37] See Kolbe, A. L., Tye, W.B. and Myers, S. C. (1993) *Regulatory Risk: Theory with Applications to Natural Gas Pipelines and Other Industries*, Boston: Kluwer Academic Publishers, Chapters 2 and 3; Kolbe, A. L. and Tye, W. B. (1991) "The *Duquesne* Opinion: How Much `*Hope*' is There for Investors in Regulated Firms?," *Yale Journal on Regulation*, 8(1), pp. 113-157; and references therein.

[38] Federal Energy Regulatory Commission, Docket No. RM78-12, *Alaska Natural Gas Transportation System Incentive Rate of Return*, Notice of Delegate Report and Order Directing Tariff Filing, Issued February 22, 1979.

[39] Other FERC decisions have also recognised the issue of asymmetric risk. See Federal Energy Regulatory Commission (1996) *Promoting Wholesale Competition through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*; Order No. 888, Final Rule, issued April 24.

[40] California Public Utilities Commission (1989) Decision *Re Pacific Bell*, Application 85-01-034, 107 PUR4th, October 12, pp. 137-38.

costs of repairing hurricane damage caused by Hurricane Iniki.[41] Whereas, as noted above, firms in competitive industries would have earned a return above their cost of capital in non-hurricane years, Kauai had been prevented from doing so by regulatory rate-setting.

Finally, we note that OffGAR's recent Draft Decision on the Access Arrangement for the Parmelia Pipeline appears to recognise the issue of asymmetric risk. In that Decision, OffGAR rejects a DORC valuation of the Parmelia Pipeline on the grounds that it might create a windfall profit by giving the owner revenues higher than those it might have reasonably expected at the time of purchase:[42]

> iii. a DORC value of the Initial Capital Base may provide CMS with a substantial windfall revenue above the earnings from gas transportation that CMS may reasonably have expected at the time of purchase of the pipeline;

Denying windfall profits imposes an asymmetric risk if the purchaser remains vulnerable to "windfall losses". However, the Draft Decision implicitly recognises that its rejection of windfall profits threatens to impose asymmetric risk. One of its grounds for rejecting a DAC valuation is that it would create a "windfall loss":[43]

> A DAC valuation methodology is not considered appropriate for valuation of the Initial Capital Base as *the DAC value would most likely be less than the reasonable expectation of CMS of the value of the pipeline assets at the time of purchase*. For the Parmelia Pipeline the DAC value is expected to be close to zero and would not reflect the capital investment made by CMS in the pipeline in line with reasonable expectations of tariff levels and cash flows.
>
> The Regulator considers that a more appropriate valuation of the Initial Capital Base would be one that sought to reflect the reasonable expectations of CMS at the time of purchase of the pipeline assets, as well as to the reasonable expectations of Users as to the implications of the new regulatory regime. (sic) (Emphasis added)

The Parmelia Draft Decision therefore appears to create a regulatory precedent in WA for the recognition and avoidance of asymmetric risk.

Asymmetric Risk and the DBNGP

If regulatory policy chooses an asset value or other regulatory parameters that produce rates below those stipulated in Epic's winning bid, then Epic's shareholders will have been harmed by an asymmetric risk. Epic placed two bids [this information has been deleted. See NOTE at start of Submission]. If a rate base below Epic's purchase price is now adopted, then the result will be to have effectively "mixed and matched" Epic's higher bid with lower tariffs. The situation is asymmetric unless one somehow believes

[41] Hawaii Public Utilities Commission (1996) *Citizens Utilities Company, Kauai Electric Division, Decision and Order No.* 14859, P.U.C. Haw. 94-0308 (Aug 7, 1996).

[42] OffGAR, cited at note 29, p. 59.

[43] *Ibid*, pp. 59-60.

there was an equal chance that the government would pick a *lower* bid and match it with *higher* tariffs.

Setting a regulatory asset base lower than Epic's purchase price might therefore have a chilling effect on future bids for government assets in WA. Investors would know that high bids for privatised assets would expose them to serious financial losses. However, they would have no guarantee of keeping the possible windfalls should they succeed with relatively low bids. Such windfalls are politically unpopular, and have been appropriated by governments in the past, both by changes in regulatory methodology and legislation. As noted above, OffGAR's recent Draft Decision on the Parmelia Pipeline explicitly rejects a valuation that might provide the owner with a "substantial windfall".[44]

If Epic is not given the opportunity to earn back the price it paid for the DBNGP, future investors in WA can therefore be expected to fear becoming subject to asymmetric risk. The chilling effect of asymmetric risk on investment will not be confined to bids on future privatisations. Regulated firms will hesitate to undertake further investments, such as expansions in capacity, if they fear asymmetric treatment, giving rise in the long run to significant distortions and inefficiency.

Finally, we note again that our proposal leaves Epic exposed to at least two forms of asymmetric risk. First, Epic continues to bear the risk that future volumes will be less than forecast, leading to under-recovery of capital, while future volume levels higher than currently forecast will not enable it to earn more than its cost of capital. Second, Epic bears the risk that a future prudence review may disallow some of its capital investment, removing it from the asset base without compensation, again without enjoying any complementary upside risk.

[44] *Ibid*, p. 59.