Default price-quality path reset for gas pipelines

November 2012

Project team:

Tom Hird
Daniel Young

CEG Asia Pacific
Suite 201, 111 Harrington Street
Sydney NSW 2000
Australia
T: +61 2 9881 5754
www.ceg-ap.com

Table of Contents

List of Tables

1 Introduction

1. CEG has been asked by Vector to review the Commerce Commission's Revised Draft Decision in respect of the initial default price-quality paths for gas pipeline services (hereafter, the 'Draft Decision').

2. The Commission's Draft Decision populates and implements a building block model of costs with forecasts of operating and capital expenditure, developed by the Commission.

3. In simplified terms, the Commission estimates its price reset adjustment by:

   - forecasting costs into the future and then computing the present value of all costs for each gas pipeline business over the regulatory period from 1 July 2013 to 30 September 2017;
   - calculating an allowed projected path of revenues over the regulatory period, increasing in real terms at the rate of "real revenue growth" calculated by the Commission for each business, that recovers this present value of costs; and
   - calculating the percentage difference between the allowed projected revenue in the 2013/14 financial year against the projected revenue that would occur if there were no price reset. This percentage difference is the price reset adjustment.

4. For Vector, these calculations result in a price reset adjustment of -15.6% for its gas distribution business and -25.2% for its gas transmission business.

5. We have a number of recommended improvements tothe Commission's proposed approach. Our greatest concern is with respect to its proposed volume growth assumptions in its constant price revenue growth analysis. The values that it uses for this purpose are inconsistent with those that it proposes to use for projecting opex growth and inconsistent with the method used elsewhere in its Draft Decision to make projections on the basis of historical trends.

6. The remainder of this report is set out as follows:

   - Section 2 sets out the Commission's basis for estimating real revenue growth for each firm;
   - Section 3 reviews the Commission's estimates of forecast operating expenditure;
   - Section 4 examines the methodology used by the Commission to formulate forecasts of capital expenditure; and
   - Section 5 sets out the combined effects of the changes that we recommend to the Commission's approach.

2 Constant price revenue growth

7. The Commission's estimates of constant price revenue growth (CPRG) for each of the gas distribution and transmission pipelines covered by the Draft Decision are set out at Table 2-1 below.

Table 2-1 Commission's estimates of constant price revenue growth

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
GasNet	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%
Powerco	0.48%	0.48%	0.48%	0.48%	0.48%	0.48%
Vector (distribution)	0.63%	0.63%	0.63%	0.63%	0.63%	0.63%
Maui	-4.11%	-6.07%	-6.02%	-6.12%	-6.17%	-4.85%
Vector (transmission)	-0.24%	-1.02%	-0.71%	0.27%	0.27%	0.27%

Source: Commerce Commission modelling

8. The role of CPRG in the Commission's regulatory modelling is to provide the rate of growth in real terms that the Commission assumes will occur in forecast revenues. The higher is CPRG the lower initial prices must be in order to deliver any particular present value of revenues over the regulatory period. In addition, the higher is CPRG the more backloaded is the recovery of economic costs (i.e., a greater proportion of the present value of costs is assume to be recovered in future years). Similarly the lower is CPRG, the more frontloaded the recovery of economic costs over the regulatory period.

9. The Commission's methodology for determining CPRG is, at a high level, to determine the forecast changes in gas throughput and customer numbers for each pipeline and to weight these by the respective shares of revenues earned from variable and fixed charges.

10. Our principle concern with the Commission's approach is the inconsistency between methodologies, data and outcomes in its approach for forecasting volume growth for this purpose as compared to its approach to forecasting volume growth for other purposes in its Draft Decision and its general approach to developing projections in its Draft Decision.

2.1 Inconsistent use of volume growth assumptions

11. To estimate forecasts of customer numbers, the Commission relies upon trend growth in customer numbers by category over the last four years on a firm by firm basis. This is also the methodology used by the Commission to forecast growth in pipeline length and gas volumes in respect of its forecasts of operating costs

elsewhere in its Draft Decision (these trends are calculated over five, not four, years).

12. However, for the purpose of its CPRG, the Commission constructs forecasts of gas volumes using inputs sourced from the Concept Consulting study. This results in rising gas volume forecasts which is in contrast to the falling gas volumes embodied in historical trends for Vector.

13. It is somewhat speculative for the Commission to adopt a forecast of positive volume growth based on the concept study when Vector's historical trends have shown declines of more than 1.5% pa in gas volumes (and declines in customer numbers). An alternative assumption would be to simply assume zero growth in all gas volumes (giving roughly equal weight to Vector's historical growth and the Commission's analysis from the Concept study).

14. In any event, whatever approach is adopted it must be consistent across the CPRG and opex estimates. In the draft decision the Commission has used:

- declining gas volumes, based on historical trend, as a basis for forecasting volume related opex growth; and
- rising gas volumes, based on analysis in the Concept study, as a basis for forecasting volume related constant price revenue growth.

15. These are clearly inconsistent approach. The effect of which would be, assuming a positive elasticity for volume related opex, that Vector would be assumed to:

- need less revenue and lower prices to cover lower volumes causing lower opex; while
- at the same time need lower prices to reach its revenue target due to higher volumes causing higher revenues at given prices.

2.2 Mapping customers from the Concept study

16. For gas distribution businesses, the Commission forecasts changes in gas throughput using parameters sourced from the Concept Consulting study. Specifically, the Commission sources:

- parameters used by Concept to forecast future gas use by category of use, including space heating, water heating and process heating;
- weights assigned by Concept to the use each heating type by time of use (TOU) and non-time of use (non-TOU) users.

17. As a result, Commission calcluates gas volume growth of 1.3% per annum for TOU users and 0.6% per annum for non-TOU users. This is consistent with the way that Concept Consulting uses these inputs in its own analysis.

18. The Commission then assumes that:

- all residential customers are non-TOU users;
- all industrial customers are TOU users; and
- commercial customers are half TOU and half non-TOU users.

19. This is a significant simplifying assumption made without any clear basis. The Commission's constant price revenue growth spreadsheet contains historical volume information that, when cross-referenced against the volumes in Concept's study, suggests the assignations made by the Commission are implausible and place too much weight on the growth of TOU customers.

20. For example, the Commission's breakdown of Vector's gas volumes in 2011 indicates that approximately two-thirds of sales are to industrial customers, and the remainder split evenly between commercial and residential. However, the moderate growth case in the Concept study envisages approximately equal consumption in the TOU and non-TOU category. These relative proportions are shown in Table 2-2 below.

Table 2-2 Comparison of volume breakdowns – Commission and Concept

	Commission: Vector (2011)		Concept: North Island (2012)	Concept: North of North Island (2012)
Industrial	65.6%	Non-TOU	49.6%	40.2%
Commercial	18.4%	TOU	50.4%	59.8%
Residential	16.0%			

Source: Concept Consulting Group Limited, Gas Supply and Demand Scenarios 2012 – 2027, August 2012, and Concept's model.

21. Based on either of the Concept weightings across TOU and non-TOU customers, it is not plausible to suggest, as the Commission has, that all industrial customers and half of commercial customers would be TOU customers. The weightings in Table 2-2 above suggest that at a minimum it would be reasonable to assume that:

- all commercial customers are non-TOU users; and
- some residual percentage of industrial customers (between 8% and 19%) are also non-TOU users.

3 Forecasts of operating expenditure

22. The Commission's approach to forecasting operating expenditure is to assume that growth in these costs are influenced by three drivers, being:

- changes in network scale, where this is proxied by:
  - network length;
  - energy throughout; and
  - number of customers.
- changes in the productivity of operating expenditure; and
- changes in input prices for operating expenditure.

3.1 Calculation of total opex growth

23. As was the case in its electricity draft decision, we consider that the Commission has made in error in treating additively the different sources that comprise overall growth in operating expenditure.

24. For example, in combining estimates of growth from opex price input factors, opex partial productivity factors, scale due to changes in network length, scale due to changes in gas volume and scale due to changes in number of customers, the Commission simply adds together these sources of growth into a combined total.

25. As set out in our previous report for Vector in response to the Commission's electricity draft decision, it is appropriate for elasticity estimates to be combined multiplicatively.[1] More generally, it is appropriate to take into account interactions between all elements of opex growth and this is achieved by combining separate growth elements with the use of the Fisher equation. We note that this is consistent with the approach used by the Commission to combine real and inflationary effects to estimate a nominal rate of return.

[1] CEG, *Default price quality path reset*, October 2012, p. 9

4 Forecasts of capital expenditure

26. The Commission proposes to allow average forecast network capital expenditure of up to, but not exceeding a limit set at 20% greater than the average of constant price network capital expenditure over the period 2008 to 2011.

27. In its Draft Decision, the Commission sets out the rationale for this approach:[2]

> *B6 We propose to apply a limit to each supplier's forecast because:*
>
> *B6.1 by relying on each supplier's forecast, we provide suppliers with an incentive to systematically bias their forecast to increase their starting price, eg, by adopting low risk forecasting assumptions*
>
> *B6.2 applying a limit is consistent with the overall regime where customised price-quality paths are the mechanism to address material step changes in capex.*
>
> *B7 The limit constrains the effect that the incentive for a supplier to systematically bias its forecast might have on consumers. Any supplier that faces a change above our limit may consider a customised price-quality path proposal.*

28. We have a number of concerns about the Commission's proposal to place a cap on forecasts of network capital expenditure and its reasons for doing so. In our view, the Commission's proposal does not distinguish between new and replacement capital expenditure, and by failing to do so is likely to require a customised price path for businesses to get "stay in business" capex plans approved by the Commission. A default price path that cannot achieve even this must be regarded as very ineffective.

29. We are also concerned that the choice of a limit set at 20% is arbitrary. On the basis of the evidence available to the Commission, there is quite considerable year-to-year variation in capital expenditure, particularly for transmission businesses but also for distribution businesses. The variation in capex that is apparent over the last five years suggests that 20% 'headroom' may not be sufficient to trigger a customised price path solely for a business undertaking routine 'stay in business' cyclical capital expenditure.

2 Commerce Commission, *Revised Draft Decision on the Initial Default Price-Quality Paths for Gas Pipeline Services*, October 2012, pp. 48-49

4.1 New capex and replacement capex

30. In setting a maximum level of network capital expenditure, the Commission does not distinguish between new capital expenditure and replacement capital expenditure. In our view, this distinction is important, particularly in light of the Commission's rationale for imposing a limit on forecast spending.

31. Gas transmission, in particular, (but also gas distribution to a lesser extent) is an industry that faces an extremely 'lumpy' profile of capital expenditure. This applies both to expenditure involved in replacing existing capital and to proposals for augmentation. Given the long lives of assets utilised in this industry, it would not be unusual to have an extended period of time with very low capital expenditure requirements, followed by a period of relatively high expenditure associated with an asset replacement program or an augmentation.

32. This profile is reflected in the historical data considered by the Commission. Table 4-1 below shows that Vector's transmission network capital expenditure was as high as $12.6 million in 2010 despite being less than half that in prior years. The data series for Powerco and Vector's distribution business also exhibits a great deal of volatility.

Table 4-1 Constant price profile of historic network capital expenditure, 2008-2011

	Gasnet	Powerco	Vector distribution	Maui	Vector transmission
2008	667	8,927	17,146	723	5,311
2009	402	8,757	22,957	326	5,703
2010	521	10,237	11,302	899	12,572
2011	561	6,462	21,373	39	7,911
Average	538	8,596	18,195	497	7,874

Source: Commission opex and capex projections model

33. A similar profile is reflected in forecasts of network capital expenditure provided by the suppliers, particularly those for Vector's distribution business and the two transmission gas pipelines as shown at Table 4-2 below.

Table 4-2 Constant price supplier forecasts of network capital expenditure, 2012-2017

	Gasnet	Powerco	Vector distribution	Maui	Vector transmission
2012	560	9,910	18,687	1,966	14,100
2013	606	9,651	20,704	4,420	17,808
2014	593	9,785	24,534	40,060	35,312
2015	608	10,865	15,973	2,185	16,028
2016	619	10,954	12,073	1,980	13,368
2017	617	11,043	12,097	2,835	13,195
Average (2013-2017)	**609**	**10,460**	**17,076**	**10,296**	**19,142**

Source: Commission opex and capex projections model

34. The Commission states that "customised price-quality paths are the mechanism to address material step changes in capex".[3] We agree that large new capital programs could be subject to specific review by a customised price path. However, capital expenditures that are required merely to replace existing assets should not have to go through this process. That is, it would be a remarkably ineffective default price path that required businesses to opt for a customised price path in the event that they wished to engage in significant replacement expenditure just because it was above the average for recent years.

35. One simple method for the Commission to cross-check whether its allowances are reasonable from this perspective is to look at the time series of depreciation used in its regulatory modelling. Depreciation by itself does not give a 'hard and fast' estimate of the amount that must be spent in any one year on asset replacement, but it does provide a ballpark 'average' measure as to what might be reasonable over a period of time.

36. We compare total depreciation to total capital expenditure (including both network and non-network assets). To our knowledge there is no breakdown of depreciation into components that would allow us to assess network capital expenditure separately.

37. Table 4-3 below shows the total capital expenditure allowed by the Commission in nominal terms, including the average over 2012/13 to 2016/17.

---

3 Ibid, p. 49

Table 4-3 Total allowed nominal capital expenditure, 2012-2017

	Gasnet	Powerco	Vector distribution	Maui	Vector transmission
2012	657	11,121	22,136	140	11,728
2013	712	10,989	24,450	310	13,816
2014	711	11,321	28,853	2,809	23,430
2015	742	12,706	20,412	164	13,393
2016	772	13,103	16,667	153	12,221
2017	786	13,485	17,053	220	12,386
Average (2013-2017)	**744**	**12,321**	**21,487**	**731**	**15,049**

Source: Commission opex and capex projections model

38. Table 4-3 below shows the total capital expenditure forecast by suppliers. Because the Commission's opex and capex modelling only contains projections by suppliers of network capital expenditure, we have constructed a forecast of total capital expenditure by combining this with the Commission's forecast of non-network capex.

Table 4-4 Total supplier forecast nominal capital expenditure, 2012-2017

	Gasnet	Powerco	Vector distribution	Maui	Vector transmission
2012	657	11,172	22,136	1,987	18,597
2013	712	11,039	24,450	4,511	22,593
2014	711	11,373	28,853	41,544	41,141
2015	742	12,765	20,412	2,322	21,607
2016	772	13,164	16,667	2,155	19,235
2017	786	13,547	17,053	3,149	19,458
Average (2013-2017)	**744**	**12,378**	**21,487**	**10,736**	**24,807**

Source: Commission opex and capex projections model

39. Finally, Table 4-5 below shows the projections of depreciation sourced from within the Commission's Draft Decision financial model for each business.

Table 4-5 Nominal allowed depreciation, 2012-2017

	Gasnet	Powerco	Vector distribution	Maui	Vector transmission
2012	957	8,423	13,783	7,257	18,003
2013	981	8,572	14,410	7,401	18,441
2014	1,019	9,188	15,271	7,537	19,157
2015	1,056	9,629	16,229	7,767	20,078
2016	1,097	10,131	17,054	7,947	20,838
2017	1,138	10,641	17,796	8,122	21,567
Average (2013-2017)	**1,058**	**9,668**	**16,152**	**7,755**	**20,016**

Source: Commission Draft Decision financial model

40. A comparison of the depreciation estimates in Table 4-5 to the forecast capital expenditures in Table 4-3 and Table 4-3 indicates that for the transmission operators in particular, where the Commission's methodology has made significant reductions to capital expenditure forecasts, the depreciation modelled by the Commission is consistent with much higher levels of capital expenditure than those allowed by the Commission. For Maui, average depreciation is 961% higher than the level of capital expenditure that the Commission has capped it at, and for Vector (transmission) the difference is 33%. However, for Powerco and Vector (distribution) the depreciation forecasts are on average lower than average capital expenditure allowed by the Commission.

41. We consider that the Commission should have regard to both historic averages of capital expenditure and projected depreciation in considering the reasonableness of forecast capital expenditures provided by suppliers. The Commission's proposed approach involves seeking a 'ballpark' estimate of what 'normal' capital expenditure is and adding 20% margin to that. In our view, an equally good ballpark estimate of normal capital expenditure is the depreciation in the value of the RAB (i.e., what must be invested to keep the RAB constant).

42. Specifically, we consider that forecasts should be deemed reasonable if they lie below the larger of:

- average historic capital expenditure (adjusted for inflation) plus 20% headroom; or
- average projected depreciation plus 20% headroom (consistent with the headroom applied by the Commission on historic capital expenditure).

43. On this basis, the Commission would accept, unchanged, the forecasts provided by GasNet, Powerco and Vector (distribution). The scaling for Maui at a total level would be a 13% reduction in forecasts compared to the 93% reduction proposed by

the Commission. Similarly, the adjustment to Vector's (transmission) forecast capital expenditure would be 3% instead of 39%.[4]

4.2 Use of 20% limit on average capex increase

44. The Commission notes that variations in capital expenditure over time are to be expected. In support of its use of 20% to determine a cap, it states:[5]

> *Variations in the level of capex relative to the past are to be expected. Fluctuations in the order of 5% will be common, certainly too frequent to justify a customised price-quality path every time, and should be accommodated within the default price-quality path.*

45. Whilst we agree that variations in the order of 5% will indeed be common, we note that much more extreme variations are readily evident from the historical and forecast evidence provided, even in constant price terms, as shown in Table 4-1 and Table 4-2 above.

46. In the case of Vector's distribution and transmission businesses, for example, the highest year of historical capital expenditure is over 100% greater than the lowest year of capital expenditure. The comparison is even more extreme when looking at the forecasts of the two transmission businesses. Although the cap used by the Commission is applied to averages over two five year periods, we think that this provides some basis for considering that, particularly for transmission businesses, 20% may not be a sufficient allowance.

47. However, we note that very little turns on this. If the Commission accepts our recommended approach of also considering depreciation (plus 20%) as an alternative benchmark against which to assess capital expenditure, then the most extreme effects of the Commission's decision will be alleviated as summarised at section 4.1 above.

[4] All these reductions are expressed at the level of total capital expenditure and in nominal terms. The Commission reports adjustments in its modelling specific to network capital expenditure and in constant price terms, which are not directly comparable to the adjustments reported here.

[5] Commerce Commission, *Revised Draft Decision on the Initial Default Price-Quality Paths for Gas Pipeline Services*, October 2012, p. 49

5 Technical modelling assumptions

48. In a previous report for Vector we have argued for changes to the Commission's financial model in order to ensure that interest deductions for tax purposes and real depreciation are modelled appropriately.[6] The same analysis is relevant to the models used by the Commission and is repeated below.

5.1 Modelling interest deductions for tax purposes

49. This error flows from an incorrect use of an annualised interest rate to estimate the level of actual interest tax deductions that would be generated by a 44% geared business.

50. Specifically, the Commission's modelling estimates tax 'as if' companies pay their tax obligations, on average, in the middle of the year (rather than the end of the year). This assumption is consistent with the Commission's overall approach where it attempts to reflect the true timing of expenditures and revenues through the year.

51. The error we identify is that the Commission's does not amend its estimate of the absolute level of interest deductions to reflect this approach. Specifically, for the purpose of estimating the absolute level of interest tax deductions, the Commission assumes that interest is paid on debt in a lump sum at the end of the year.

52. In reality, and consistent with the Commission's timing assumption on when tax is paid, businesses pay interest throughout the year. On any individual debt instrument a business will generally pay at least 2 coupon (semi-annual) payments every 12 months. On many debt instruments businesses pay 4 (quarterly) coupon payments or pay interest calculated daily on outstanding balances.[7] Moreover, businesses stagger their debt issues so that, over the total portfolio of debt, coupon payments are further spread relatively evenly throughout the year

53. The effect of this is that the absolute amount of interest paid by a 44% geared business is not the amount calculated in row 244 of the building block model for each business. The amount calculated in row 244 assumes that interest is paid in a lump sum at the end of the year. In reality, interest is paid throughout the year and, consequently, the absolute amount of interest paid is lower (although the NPV will be the same). The effect of this is that the Commission overestimates the amount of interest deductions available for tax purposes (and therefore underestimates the amount of tax liabilities). That is, while the Commission's model correctly estimates the present value of interest costs, it overestimates the absolute value of interest

[6] CEG, Default Price Quality Path Reset, October 2012, section s 2.1 and 2.2.

[7] Common practice is for fixed rate debt to have coupons paid semi-annually, for floating rate debt to have coupons paid quarterly and for bank debt to be paid daily (although this practice can be departed from).

deductions by incorrectly assuming that all interest payments are made at the end of the year.

54. This error can be fixed by calculating a daily interest rate from the annualised interest rate and estimating notional debt costs as the interest payments that would be made 'as if' all interest payments were made in a lump sum in the middle of the year. (This is modestly above the interest deductions that would be calculated if it was assumed that interest was paid daily).[8] That is, the equation in cell H244 (and similarly all other cells in this row) would change from being:

- Current formula =(H226*Leverage*Debt+H221); to be
- Proposed formula = (H226*Leverage*(Debt)/SQRT(1+Debt)+ H221).

55. The proposed formula more accurately reflects the actual practice of businesses such that debt costs are spread throughout the year. In CEG's view it might be open to the Commission to investigate further the actual profile of interest payments made throughout the year and to substitute a different formula to the one proposed that reflected a businesses' actual debt costs. However, in our view it is not open to the Commission to retain the assumption that 100% of all interest payments are made on the last day of the year because this is patently inconsistent with what businesses actually do. [9]

56. We note that similar points were made in CEG's August 2011 report[10] and the joint report by Balchin and Hird where we stated:

> *This internally consistent modelling of financing costs and interest deductions is also consistent with how an efficient firm would expect to arrange its debt financing obligations to match its cash flow to the extent possible, which may imply an even spread of interest payments over the year to approximate a midyear payment.*
>
> *Giving effect to this proposition is straightforward – the cost of debt that is used when calculating taxation liabilities merely needs to be converted to a*

8 This interest rate would be ((1+Debt)^(1/365)-1)*365 = 7.632% compared to 7.633% using the proposed formula.

9 It is relevant to note that while the Commission's building block model assumes for the purposes of estimating interest tax deductions that interest is paid on the last day of the year (with the effect that interest tax deductions are maximised and modelled tax costs are minimised). The model does not, however, provide the same dollar compensation to EDBs for their interest costs. Rather, the Commission assumes that materially lower dollar compensation is required for interest costs because businesses receive their compensation earlier than the end of the year.

10 CEG, August 2011, Review of Draft Decisions Paper on Starting Price on 2010-15 Default Price-Quality Path For Electricity Distribution. See section 4.

midyear interest rate, as demonstrated by Hird. This adjustment should also be applied when applying Equations 3 to 5 from the Balchin report.

57. The Commission did not address these submissions in its most recent decision document. This may be an understandable oversight due to the fact that these submissions were made in the context of a different model that assumed tax was being paid at the end of the year. It may be that the Commission came to the conclusion that changing this approach (the assumed timing of tax payments) made the arguments put by CEG and PwC (Hird and Balchin) moot. However, for the reasons set out above this is not the case and, for the reasons set out above, we respectfully submit that the Commission address this issue in its final model.

5.2 Modelling real depreciation

58. The Commission's modelling provides a nominal amount of depreciation in each year equal to the opening RAB (ORAB) in that year divided by the remaining life of the asset (RL) (see row 61 of each businesss cost model). However, the Commission also applies a revaluation to the ORAB equal to the assumed rate of inflation multiplied by the ORAB (see row 60). The net effect of these two operations is that the actual closing RAB (CRAB) returned to investors is given by:

$$\text{CRAB} = \text{ORAB} - \text{ORAB}/\text{RL} + \text{ORAB}^*\text{inflation} \quad (1)$$

$$= \text{ORAB}^*(1+\text{inflation}) - \text{ORAB}/\text{RL} \quad (2)$$

59. The real CRAB (expressed in the same dollars as the ORAB) is simply the above value divided by (1+inflatoin) which is equal to:

$$\text{Real CRAB} = \text{ORAB} - \text{ORAB}/(\text{RL}^*(1+\text{inflation})) \quad (3)$$

60. It follows that the amount of real depreciation (expressed in dollars of the beginning of the year) is equal to the ORAB less the Real CRAB which is equal to:

$$\text{Real depreciation} = \text{ORAB}/(\text{RL}^*(1+\text{inflation})) \quad (4)$$

61. This formula for real depreciation shows what is, in our view, an unsatisfactory element of the Commission's modelling. The amount of real depreciation returned to investors is:

- in the presence of positive inflation, less than the real depreciation implied by the remaining life of the asset; and
- reduces with increases in the level of inflation.

62. The effect of this is that the higher is the inflation rate the more backloaded is the level of *real* cost recovery. We consider that the goal of cost models should be to deliver the same real outcomes no matter what the level of inflation. We are aware of

no justification provided for a different outcome and there is, to the best of our knowledge, no other regulatory cost model that has this characteristic.

63. For example, the AER's PTRM model first calculates required depreciation in real terms (ORAB/RL) but then escalates this for inflation.[11] Such that equation (1) above becomes:

$$CRAB = ORAB - ORAB/RL*(1+inflation) + ORAB*inflation \qquad \text{(AER 1)}$$

64. Following the same algebraic approach as set out above it follows that the real depreciation delivered by the PTRM is, as it should be, simply ORAB/RL and does not depend on inflation.

65. Apart from it being illogical for the real return of capital to fall with higher levels of inflation it is also problematic in terms of ensuring financeability of the assets. Times of high inflation tend to involve high nominal debt payments and higher than usual uncertainty about the level of input costs. In this context, a reduction in the real return of capital is likely to materially raise the difficulty in finding investors willing to fund both debt and equity capital.

66. We recommend that the Commission amend its model to escalate depreciation in its model by inflation. This could be achieved for depreciation of the existing RAB at row 106 simply by multiplying the existing formula in this row (ORAB/RL) by the one plus the value in the corresponding column of row 90 (ie, 1+inflation). The same adjustment to rows 139 to 147 would also make the correction for depreciation of commissioned assets.

---

11 The PTRM is available on the AER website (eg, http://www.aer.gov.au/node/9926). The fact that nominal depreciation is set equal to real depreciation escalated for inflation can be ascertained by examining row 472 on the Assets sheet.

6 Effect of combined changes

67. In this report we have presented changes to the Commission's modelling of constant price revenue growth, operating cost forecasts and capital expenditure forecasts. Table 6-1 below shows the combined effects of these recommendations, both separately and together compared to the Commission's proposed price reset for each of the five gas pipeline businesses.

Table 6-1 Effects of recommended changes to Commission's modelling, price resets

	Gasnet	Powerco	Vector distribution	Maui	Vector transmission
Commission's proposed price reset	-2.3%	+4.8%	-15.6%	+2.0%	-25.2%
Changes to the Commission's price reset model	-1.8%	+5.4%	-15.1%	+2.6%	-24.8%
Combined changes to constant price revenue growth*	n.a.	n.a.	-15.2%	n.a.	n.a.
Changes to the Commission's opex modelling	-2.3%	+4.8%	-15.6%	+2.0%	-25.2%
Combined changes to capital expenditure	-2.3%	+4.8%	-15.6%	+7.7%	-23.4%
All changes together	**-1.8%**	**+5.4%**	**-14.7%**	**+8.4%**	**-22.9%**

* This change reflects the changed assumption about the prevalence of ToU tariffs – it otherwise retains the Commission's methodology relying on the Concept Study.