ESSENTIAL SERVICES COMMISSION

Review of Gas Access Arrangements

Final Decision

October 2002

2nd floor, 35 Spring Street, Melbourne 3000
Telephone (+61 3) 9651 0222 *Facsimile*: (+61 3) 9651 3688
Email: reception@esc.vic.gov.au
Web site: http://www/esc.vic.gov.au

PREFACE

On 2 April 2002, the three Victorian gas distributors each submitted proposed Revisions to their existing Victorian gas distribution Access Arrangements to the Essential Services Commission for approval. Envestra also subsequently submitted proposed Access Arrangement Revisions in relation to its Albury gas distribution network, which has been cross-vested from New South Wales to Victoria.

Under the *National Third Party Access Code of Natural Gas Pipelines* (the Gas Code), the Commission is required to decide whether to approve or not approve the proposed Revisions. The Commission may approve the proposed Revisions only if it is satisfied that the Access Arrangement as revised would contain the elements and satisfy the principles set out in sections 3.1 to 3.20 of the Gas Code. In doing so, it must also consider various factors set out in section 2.24 of the Gas Code.

The Commission has completed its assessment of the proposed Revisions in accordance with the provisions of the Gas Code. This report sets out the Commission's Final Decision in relation to the gas distributors' proposed Revisions. In summary, the Commission has decided to not approve the gas distributors' proposed Revisions and has set out the nature of amendments that the Commission requires before it will approve them.

In undertaking its assessment of the distributors' proposed Revisions, the Commission has undertaken extensive consultation on the approach to this review, the key issues and information presented. This report sets out the relevant issues, information and the analysis underpinning the Commission's Final Decision not to approve the proposed Revisions.

The Commission invites each of the distributors to submit their revised Access Arrangement Revisions amended to reflect the requirements of this Final Decision by **COB Wednesday 6 November 2002**. These should be forwarded electronically to:

gas.review@esc.vic.gov.au

If approved, the Access Arrangements as revised will establish the terms and conditions for third party users to gain access to the services offered by gas distribution pipeline owners and operators in Victoria and Albury for the five-year period commencing 1 January 2003.

Further information related to this review is available on the Commission's website at www.esc.vic.gov.au.

JOHN C TAMBLYN
Chairperson

ROBERT SCOTT
Commissioner

TABLE OF CONTENTS

Part A

EXECUTIVE SUMMARY AND REQUIRED AMENDMENTS

EXECUTIVE SUMMARY

In April 2002, the three Victorian gas distributors each submitted proposed Revisions to their existing Victorian gas distribution Access Arrangements to the Essential Services Commission for approval. Envestra also subsequently submitted proposed Access Arrangement Revisions in relation to its Albury gas distribution network, which has been cross-vested from New South Wales to Victoria.

Under the *National Third Party Access Code of Natural Gas Pipelines* (the Gas Code), the Commission is required to decide whether to approve or not approve the proposed Revisions. The Commission may approve the proposed Revisions only if it is satisfied that the Access Arrangement as revised would contain the elements and satisfy the principles set out in sections 3.1 to 3.20 of the Gas Code. In doing so, it must also consider various factors set out in section 2.24 of the Gas Code.

The Commission has completed its assessment of the proposed Revisions in accordance with the provisions of the Gas Code. This report sets out the Commission's Final Decision in relation to the gas distributors' proposed Revisions. In summary, the Commission has decided to not approve the gas distributors' proposed Revisions and has set out the nature of amendments that the Commission requires before it will approve them.

In undertaking its assessment of the distributors' proposed Revisions, the Commission has undertaken extensive consultation on the approach to this review, the key issues and information presented. This report sets out the relevant issues, information and the analysis underpinning the Commission's Final Decision not to approve the proposed Revisions.

The Commission is required to assess these proposed Revisions in accordance with the provisions of the *National Third Party Access Code of Natural Gas Pipelines* (the Gas Code). In particular, it is required to decide whether to approve or not approve the proposed Revisions. If approved, the Access Arrangements as revised will establish the terms and conditions for third party users to gain access to the services offered by gas distribution pipeline owners and operators in Victoria and Albury for the five-year period commencing 1 January 2003.

In making its Final Decision on each of the distributors' proposed Revisions, the Commission has carefully considered the requirements of the Gas Code and the Tariff Order. The Commission notes that throughout this review, the distributors and a number of other interested parties have made submissions to the Commission commenting on how the Commission should interpret these requirements in making its decision. The gas distributors each referenced the broader public debate on infrastructure regulation and urged the Commission to have regard to its main themes in deciding whether to approve or not approve their proposed Revisions for the 2003-07 access arrangement period.

After the Commission's due date for submissions in response to the Draft Decision, on 23 August 2002 the Full Court of the Supreme Court of Western Australia handed down its judgment in the matter of: Re Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Ltd & Anor [2002] (the 'Epic judgment').

Shortly thereafter, the Federal Assistant Treasurer released the Productivity Commission's final report on the review of the national third party access regime[1], and announced its decision, *inter alia*, to incorporate an objects clause in Part IIIA of the Trade Practices Act 1974 that clarifies that the object of that part is to:

> (a) promote the economically efficient operation and use of, and investment in, essential infrastructure services, thereby promoting effective competition in upstream and downstream markets; and
>
> (b) provide a framework and guiding principles to encourage a consistent approach to access regulation in each industry.

Whilst both these developments represent important milestones in the evolution of the principles and practice of economic regulation of access to essential infrastructure, the guidance provided by the WA Supreme Court's decision in the Epic case is fundamental since it is directed at the specific provisions of the Gas Code that the Commission is bound to apply.

Accordingly, the Commission has considered its implications carefully in making this Final Decision.

In summary, the Commission has decided to not approve the gas distributors' proposed Revisions and has set out the nature of amendments that it requires before it will approve them. A summary of the amendments required follows this executive summary and the detailed reasons for the Commission's Final Decision are set out in Part B of this report, which is structured around the main components of the Access Arrangements:

- reference services;
- assessing total revenue; and
- price controls and reference tariff policy.

The Commission's conclusions with respect to each of these components is summarised below.

Reference services

The details of the Commission's response to the distributors' service proposals are contained in section 2.

[1] Productivity Commission, *Review of the National Access Regime*, Report No. 17, 2001.

The Commission has accepted the main components of the distributors' proposals, including the proposals that the current principal *reference services* of gas transportation or haulage be continued, with Tariff V customers receiving a meter and service pipe, and Tariff D customers paying for these assets separately. The Commission has also approved the distributors' proposed reference and ancillary reference services.

Unreticulated towns

An important issue for many customers is the regulatory arrangements for the extension of the gas distribution network to unreticulated towns. The Commission has approved arrangements proposed by the distributors, which reflect the arrangements adopted by the Commission in its 'Interim Policy for Extensions to Currently Unreticulated Townships'. The arrangements are designed to ensure network extensions can proceed without the distributor concerned being disadvantaged by virtue of projects being commenced within a five-year regulatory period, while retaining flexibility for the distributors to deal with individual projects separately.

However, one of the Commission's key concerns is to ensure that all parties have clear expectations as to the implications of regulatory arrangements for projects of this type that are undertaken over the next regulatory period. To this end, and in the interests of promoting transparency, the Commission has set out in this Final Decision it own understanding of how these arrangements would operate.

Guaranteed service levels

The Commission considers that it is desirable for each of the distributors to introduce a GSL scheme and for relevant definitions, thresholds and payments to be consistent across distributors. In view of the fact that the GSLs represent a service level commitment to end use customers rather than retailers, the Commission considers that the obligations relating to the GSL schemes are most appropriately included in the Gas Distribution System Code and applied to each of the distributors rather incorporated into the distributors' proposed terms and conditions. There are some additional requirements for Envestra in relation to its Albury network, which reflect the fact the nature of legislative arrangements that apply to it. The nature of the scheme is largely as proposed by TXU and Multinet, with some modifications.

Total revenue & 'X' Factors

The form of regulation proposed by the distributors and adopted by the Commission is referred to in the Gas Code as the 'price path' approach.[2] This approach involves determining a path for reference tariffs that is forecast to deliver a revenue stream calculated consistently with the principles in the Gas Code and section 9 of the Tariff Order. Once the CPI-X price caps are set using this approach, no adjustments are made to take into account subsequent events until the commencement of the next regulatory period.[3]

The 'X' Factors

The X factors adopted by the Commission reflect its conclusions regarding the revenue stream referred to above, and its conclusions regarding the forecast level of demand (based on 'normal' weather conditions) for the next access arrangement period. The X factors adopted for this Final Decision are provided in the table below.

TABLE 1
FINAL DECISION: REFERENCE TARIFF P_0 AND X FACTORS TO APPLY TO EACH DISTRIBUTOR, 2003-07

	P_0	X
Envestra Albury	2.6	1.0
Envestra Victoria	9.9	1.0
Multinet	2.0	-0.7
TXU	2.0	-0.5

This table implies a reduction in weighted average prices for Envestra Albury of 2.6 per cent in 2003 in real terms from current prices, 9.9 per cent for Envestra Victoria and 2.0 per cent for Multinet and TXU. It also implies a further reduction in weighted average prices in each subsequent year of the access arrangement period of 1.0 per cent for Envestra's Albury and Victorian network, with an increase of 0.5 per cent for TXU and 0.7 per cent for Multinet.

The weighted average price changes included in this Final Decision reflect the change required to existing prices to bring the revenue that is forecast under reference tariffs over the next five years into line with the stream of revenue (total revenue) calculated for each of the distributors by the Commission in accordance with the Gas Code. The latter stream of revenue has been calculated with reference to a return on the value of their investments in the regulated activities, a return of that investment over time through depreciation and operating and maintenance expenses. A forecast of sales over the next five years is then required to forecast the revenue expected to be received under reference tariffs.

2 Section 8.3(a) of the Gas Code. This form of regulation is also referred to as CPI-X or price cap regulation.

3 This contrasts with the 'cost of service' approach described in the Gas Code, which envisages adjustments being made to reference tariffs in light of actual outcomes to ensure that distributors recover the costs of service provision.

The required weighted average price changes reflect the interaction of a number of complex factors, and so it is not possible to dissect the price changes with surgical precision. The interaction between these factors is discussed in section 3.2. One of the factors that will influence required price changes is the difference between the revenue that would have been earned in 2002 under 'normal' weather compared to the 1998 forecasts. Some of the differences in required price changes across the distributors can be explained by the implications of the current form of price control and the rebalancing control for the distributors' approved prices (and hence weather-normalised revenue) for 2002, which have resulted in different 2002 prices than those forecast in 1998. A second factor that will influence the required price changes is the difference in the revenue benchmarks set at the 1998 Review and those determined in the current review. Differences in the accuracy of cost forecasts for the 1998-02 period and the size of the future expenditure programs, amongst other things, will influence the extent of differences in benchmarks between the previous and current review.

Finally, in interpreting the X factors, a number of other factors need to be taken into account. First, the Commission has decided to incorporate an annual adjustment for the actual licence fees paid by each distributor onto the 'base' prices referred to above, rather than including an allowance for these fees in the revenue benchmarks.

Secondly, the distributors in Victoria and Albury are in the process of implementing systems to facilitate full retail contestability. In Victoria, the Government has put in place a separate regulatory instrument to allow for the recovery of these costs. This will result in a charge in excess of the price for the distribution of gas referred to above. Moreover, the Commission has replicated the Victorian arrangements for Albury, so that these costs will also be recovered through a charge in addition to the distribution charges discussed above.

Assessing Total Revenue

The Commission's overall approach to assessing total revenue is set out in section 3.1. As noted above the Commission has carefully considered the responses to its Draft Decision and the guidance provided by the Epic judgement. There are a number of components that contribute to the calculation of the revenue stream used for the purposes of establishing the X factors. The approach is generally referred to as a 'building block' approach and includes forecasts and assumptions relating to:

- Operating expenditure (section 3.3);
- Capital expenditure (section 3.4);
- Establishing the 2003 capital base (section 3.5);
- The cost of capital (section 3.6);
- Regulatory depreciation and the treatment of redundant capital (section 3.7); and
- Efficiency carryover (section 3.8).

In summary, the Commission has not adopted the total revenue proposed by the distributors, which reflects different views regarding the various forecasts, assumptions, methodologies and other matters relating to the components that make up the total revenue figure, as depicted in the table below.

TABLE 2
COMPONENTS OF TOTAL REVENUE
($ million in July 2001 prices)

	Envestra - Albury		**Envestra- Victoria**		**Multinet**		**TXU**	
	Proposed	Final Decision	Proposed	Final Decision	Proposed	Final Decision	Proposed	Final Decision
Return on assets	10.1	8.3	264.4	230.2	334.4	270.9	283.2	263.7
Regulatory depreciation	4.3	4.2	113.7	123.1	97.1	174.0	80.5	125.1
Operating expenditure	8.9	5.8	215.2	177.9	237.0	192.5	206.0	198.7
Efficiency carryover	-	-	-	-	10.7	19.0	-	-
Tax wedge	1.7	0.4	38.3	8.8	10.5	20.0	17.3	5.3
KD Constrained factor				0.7		5.7		2.8
TOTAL [a]	**24.9**	**18.6**	**631.7**	**540.8**	**689.7**	**682.1**	**587.0**	**595.6**

a Columns may not add due to rounding.

The return on assets figure adopted by the Commission is lower than that proposed by the distributors. This reflects the differences in the real after-tax cost of capital of 6.8 per cent, compared to the distributors' proposals, which ranged from 7.0 to 7.9 per cent. The capital expenditure forecast used by the Commission is also lower than that proposed by the distributors.

Nevertheless, substantially increased capital expenditure proposals have been accepted in the case of Multinet and TXU, on the basis of safety and reliability requirements. The Commission intends to initiate appropriate monitoring arrangements to ensure that the benefits of these customer-funded network improvements are delivered during the period[4].

The differences in the regulatory depreciation used by the Commission and each of the distributors reflects in part the different price outcomes in this Final Decision, since the distributors put forward depreciation proposals that sought to take into account, amongst other things, the impacts on prices over the next access arrangement period.

4 The Commission will look to implement appropriate regulatory arrangements to ensure that Multinet and TXU implement the plans upon which the capital expenditure forecasts are based.

Operating expenditure forecasts adopted by the Commission are lower than the distributors' estimates, reflecting a range of different assumptions and the proposal by the Commission to allow for the recovery of licence fees through the annual tariff approval process.

The efficiency carryover amounts are based on the carryover of gains made during the first access arrangement period. The Commission's approach provides for an allowance for additional customers connected over and above the forecasts upon which the expenditure benchmarks were based.

The 'tax wedge' refers to the estimate of tax payable in relation to regulated distribution activities, which is based on certain benchmark assumptions rather than the specific arrangements of each distributor. The amounts used by the Commission are lower than those proposed by the distributors, reflecting different views and assumptions regarding the various matters that make up the forecast.

The KDt factor is a correction factor relating to the operation of the existing price control arrangements.

The specific details are provided in the sections listed above.

The form of price controls and tariffs

Each of the distributors have proposed a 'tariff basket' *form of price control* as part of their proposed Revisions, which the Commission has approved. Importantly, the Commission has made a number of adjustments to the price control formula proposed by the distributors to reflect:

- an adjustment (referred to as an L-factor) to allow for the recovery of *actual licence fees* paid in the previous financial year. This adjustment is to be included in each of the distributors' proposed Access Arrangements and will capture increases projected for Victoria with respect to the 2001-02 year;
- an adjustment to Envestra's Albury price control formula to replicate the Victorian Order in Council *FRC cost recovery process* to allow Envestra to recover the costs of implementing FRC through a separate reference tariff component.

The fixed principles relating to the current arrangements contain constraints on the extent to which individual tariffs can be 'rebalanced' within the price cap that applies to tariffs on average. The distributors have proposed widening or removing the rebalancing constraints on tariffs. The Commission considers that a *rebalancing* control of CPI+2 per cent would appear to be reasonable in that it provides some additional flexibility to adjust tariffs and the same protection to individual customers of both electricity and gas distribution. Details of the Commission's assessment of this issue are presented in section 4.

Next steps

In response to this Final Decision, the Commission now requires each of the distributors to submit amended Revisions to their Access Arrangements that incorporate the amendments or nature of amendments specified by the Commission in this report. Distributors are required to provide their amended Revisions by **COB Wednesday 6 November 2002**.

If approved, the Access Arrangements as further revised will establish the terms and conditions for third party users to gain access to the services offered by gas distribution pipeline owners and operators in Victoria and Albury for the five-year period commencing 1 January 2003. At this stage, the Commission would anticipate releasing its Final Approval of distributors' amended Revisions by the end of November 2002.

SUMMARY OF REQUIRED AMENDMENTS

The Commission proposes to not approve the Revisions proposed by Envestra (Victoria and Albury), Multinet and TXU Networks on the basis that it is not satisfied that they contain all of the elements and satisfy all of the principles set out in the *National Third Party Access Code for Natural Gas Pipeline Systems* (the Gas Code).

In reaching this conclusion, the Commission has had regard to the various factors set out in section 2.24 of the Gas Code and the elements and principles set out in sections 3.1 to 3.20 of the Gas Code. The detailed reasons for the Commission's Final Decision are set out in Part B of this report.

Under section 2.35(b) of the Gas Code, the Commission is required to state the amendments (or nature of the amendments) that would have to be made to the proposed Revisions in order for the Commission to approve them. Subject to the outcome of the further round of public consultation that is required by the Gas Code, the Commission has determined that the following amendments (or amendments of the nature specified) would be necessary for the proposed Revisions to be granted approval under section 2.35 of the Gas Code.

TXU is required to amend Schedule 3 of its proposed terms and conditions to remove services that it has identified as ancillary reference services.

Each of the distributors is required to amend clause 3 of their proposed terms and conditions to prevent the terms and conditions from operating retrospectively.

Each of the distributors is required to amend clause 7.4(i) of their proposed terms and conditions to permit users to pay invoices within 10 *business* days of the day on which an invoice is received.

Each of the distributors is required to delete clause 7.7(c)(2) of their proposed terms and conditions and require that only the amount of the invoice that is not in dispute is to be paid.

Each of the distributors is required to amend clause 7.5(c) of their proposed terms and conditions to explicitly exclude the application of clause 7.5(a)(3).

Envestra is required to amend its proposed terms and conditions for its Albury network to:

- **define the GSL events and payments applicable to the Albury network as set out in the Final Decision; and**

· provide for the clause to cease to have effect in the event that a similar provision in the Gas Distribution System Code purports to give effect to the GSL scheme in relation to Envestra's Albury network.

Each of the distributors is required to delete clause 13.2(b)(5) of their proposed terms and conditions.

TXU is required to amend section 5.6.1 of its proposed Revisions either to:

· adopt a clause identical to that proposed by Envestra and Multinet, or to:

· replace clause 5.6.1 in its proposed Revisions with the equivalent clause from its existing Access Arrangement (clause 5.71).

Each of the distributors is required to replace clause 5.6.2(e) of their proposed Revisions with clause 5.7.2(e) from their current Access Arrangements.

Envestra is required to amend its proposed Revisions (for both Victoria and Albury) to:

· allow the carryover of efficiency gains (or losses) for a total of five (rather than ten) years [in clause B7.2(a) and B7.2(c)(1)];

· clarify that, in carrying over an accrued negative amount from one year to the next, the negative amount will be multiplied by the pre-tax WACC applying to Envestra for the third access arrangement period [in clause B7.2(c)(2)].

· reinstate its earlier proposed clauses 7.2(c)(3) and (4), to permit the Commission to exercise its discretion in choosing whether to apply any negative amounts from the one access arrangement period to the next

Multinet and TXU are required to amend their proposed fixed principles to:

· clarify that a negative carryover amount is calculated as the net present value of the carryover amount calculated for individual years, at the pre-tax WACC applying for the third access arrangement period.

· permit the Commission to exercise its discretion in choosing whether to apply any negative amounts from the one access arrangement period to the next [in Multinet clause B7.2(a)(9) and TXU B7.2(a)(10)]

Each of the distributors is required to insert a clause:

· describing the mechanism for adjusting the expenditure benchmarks in the second access arrangement period to take account of growth in calculating the

efficiency carryover amount for the third access arrangement period. The fixed expenditure amounts per connection and the benchmark connection numbers set out in [table 3.27] should be specified as part of this mechanism;

- **describing the mechanism for adjusting the expenditure benchmarks for the second access arrangement period to take account of changes in scope in calculating the efficiency carryover amount for the third access arrangement period; and**

- **clarifying that the efficiency carryover amount will be calculated as the net amount of the efficiency gains (or losses) relating to capital and non-capital expenditure.**

Envestra is required to:

- **amend B7.2(b)(6)(A) (for both Victoria and Albury) to make clear that the operating expenditure benchmark for the first year of the next regulatory period will be set with regard to actual operating expenditure in the penultimate period of the previous regulatory period and the assumed efficiency gain between the penultimate and final periods embodied in the operating expenditure benchmarks.**

- **amend B7.2(b)(6)(B) (for both Victoria and Albury) to make clear that at the regulatory review for the fourth regulatory period there will be an adjustment to the regulatory asset base to take account of the difference between forecast and actual capital expenditure in the last year of the second regulatory period.**

Each of the distributors is required to amend its proposed tariff control formulae as outlined in Appendix E, Boxes E1-E8.

Each of the distributors is required to delete the clause referring to the separate identification of 2003 tariffs.

Envestra is required to amend its proposed Revisions for both Victoria and Albury to include a reference to tariffs being set between an upper limit of the cost to bypass the network and a lower limit of the marginal cost of supply.

Each of the distributors is required to amend its proposed Revisions to indicate that it will publish an Annual Tariff Report.

Each of the distributors is required to amend its proposed formula for calculating charges for haulage reference services when a billing period straddles peak and off-peak periods, so that it reflects a straight pro-rate [Envestra 5(2)(B), TXU 5(2)(B), Multinet 5.2(B)]

Each of the distributors is required to amend its proposed Revisions to incorporate the rebalancing control formula, as outlined in Appendix E, Boxes E9-E10.

Each of the distributors is required to amend its proposed Revisions to require the Service Provider to ensure that its proposed Haulage Reference Tariffs comply with the rebalancing control for:

- **annual calendar year tariff approvals; or**
- **changes within the calendar years; or**
- **new/withdrawn Haulage Reference Tariffs.**

Each of the distributors is required to amend its proposed Revisions to provide that where the distributor proposes to introduce a new Haulage Reference Tariff and/or new Haulage Reference Tariff components:

- **the term q_{t-2}^{j} in the rebalancing control will be interpreted in relation to the estimates of the quantities that would have been sold, in relevant units, if the Haulage Reference Tariff components had existed in calendar year t-2; and**
- **the p_{t}^{j} term in the rebalancing control will be interpreted in relation to the Haulage Reference Tariff components of the parent tariff in calendar year t-2.**

Each of the distributors is required to amend its proposed Revisions to provide that where the distributor has introduced a new Haulage Reference Tariffs and/or new Haulage Reference Tariff components in calendar year t-1, the q_{t-2}^{j} term in the rebalancing control will be in relation to the estimates of the quantities that would have been sold, in relevant units, if the Haulage Reference Tariff components had existed in calendar year t-2.

Each of the distributors is required to amend its proposed Revisions to provide that where the distributor proposes to withdraw a Haulage Reference Tariff and reassign those existing distribution customers to another Haulage Reference Tariff:

- **the p_{t}^{j} term in the rebalancing control for the Haulage Reference Tariff that is proposed to be withdrawn will be interpreted in relation to the Haulage Reference Tariff components of the Haulage Reference Tariff that those existing Distribution Supply Points will be reassigned to in calendar year t;**

· the rebalancing control on Haulage Reference Tariffs will be applied separately in relation to each of the Haulage Reference Tariffs Distribution Supply Points are reassigned to, and:

TXU and Multinet are each required to amend their proposed Revisions such that the adjustment amount *(A)* applied to reference tariffs in 2004 reflects only the difference between the estimated and actual KDt factor for 2002 as set out in Appendix E, Boxes E2 & E5-E8.

Envestra is required to include in its proposed revisions for Victoria a provision that allows tariffs to be adjusted in 2004 to reflect the difference between it's estimated and actual KDt factor for 2002 as set out in Appendix E, Boxes E2 & E5-E8.

Each of the distributors is required to include an adjustment to the price control formula in 2005 that reverses the impact of the A-factor as set out in Appendix E, Boxes E3 & E5-E8.

Envestra is required to amend its proposed Revisions for Albury to include a separate Reference Tariff component outside of the main distribution price controls applying to Haulage Reference Tariffs that provides for the recovery of its costs of implementing FRC.

Specifically, Envestra is required to include a provision which states that it will charge the same tariffs for cost-recovery of FRC as those determined for its Victorian network by the Commission under the Order in Council, with the exception that, for the 2003 calendar year, these tariffs will be:

· a customer supply point charge of $1,204.79/annum; for customers consuming above 5,000GJ/annum;

· a fixed customer charge of $9.656/annum; for customers consuming less than 5,000GJ/annum; and

· a low usage volume charge of $0.241/GJ for customers consuming less than 5,000GJ/annum.

Each of the distributors is required to include the following clauses in their proposed revisions:

If the Service Provider does not submit proposed Haulage Reference Tariffs in accordance with clause 4.1(a), then

· if the left-hand side of the price control formula is greater than one, the Haulage Reference Tariffs applying in Calendar Year t-1 will continue to apply; or

· if the left-hand side of the price control formula is less than one, the Haulage Reference Tariffs applying in Calendar Year t-1 will be scaled down by the left-hand side of the price control formula, and will apply from the start of Calendar Year t.

Where the Service Provider proposes to introduce a new Haulage Reference Tariff or new Haulage Reference Tariff Component, it is required to submit proposed new Haulage Reference Tariffs or new Haulage Reference Tariff Components at least 60 business days prior to the date on which it wishes the new tariffs to commence.

The Ancillary Reference Tariffs, as set out in Schedule 2, will be adjusted by the formula outlined in Appendix E, Box E13 of this Final Decision.

Each of the distributors is required to amend its proposed change in tax pass through provisions (Clause 8) as follows:

Define a 'change in tax event' as:

· a variation, or withdrawal or introduction of a Relevant Tax, or a change in the way or rate at which a Relevant Tax is calculated, which has a material impact on the costs to the distributor of providing the Reference Services.

Define a 'relevant tax' as:

· any royalty, duty, excise, tax, impost, levy, fee or charge (including, but without limitation, any GST) imposed by an Authority in respect of the repair, maintenance, administration or management of the Distribution System (or any part of it) or in respect of the provision of the Reference Services, but excluding:

For the avoidance of doubt, charges associated with the Retailer of Last Resort function are included within this definition of a relevant tax.

Amend clause 8.2(b) to require the regulator to assess the pass through application within 30 business days.

Envestra is required to amend clause 8.1 of its proposed Revisions for both Victoria and Albury to provide notice of a change in tax event to the Commission within a period of 3 months.

Each of the distributors is required to amend its proposed Revisions to provide for X_t to be defined as follows:

· For Envestra (Albury), Xt is 0.026 for calendar year 2003 and 0.01 for each of the calendar years 2004-07;

· For Envestra (Victoria), Xt is 0.099 for calendar year 2003 and 0.01 for each of the calendar years 2004-07;

· For Multinet, Xt is 0.020 for calendar year 2003 and –0.007 for each of the calendar years 2004-07; and

· For TXU, Xt is 0.020 for calendar year 2003 and –0.005 for each of the calendar years 2004-07

Multinet is required to amend its proposed fixed principle 7.2(a)(1) to refer to the regulator utilising incentive based regulation adopting a CPI-X approach as the form of regulation to apply until the end of the third access arrangement period.

Envestra is required to amend its proposed fixed principle 7.1(e)(1) (for both Victoria and Albury) so that it applies until the end of the third access arrangement period rather than 30 years.

Multinet and TXU are each required to amend their proposed fixed principle 7.2(a)(2) to clarify that the requirement to adopt a single X factor does not preclude a P_0 adjustment in future access arrangement periods.

Multinet is required to amend its proposed fixed principle 7.2(a)(2) to clarify that the regulatory approach will be incentive-based regulation adopting a CPI-X approach.

TXU is required to delete its proposed fixed principle 7.2(a)(3).

Envestra is required to amend clause B7.2(a) and B7.2(c)(1) of its proposed Revisions (for both Victoria and Albury) to allow the carryover of efficiency gains (or losses) for a total of five (rather than ten) years.

Multinet and TXU are each required to amend their proposed fixed principles to:

· clarify that a negative carryover amount from the second access arrangement period is calculated as the net present value of the carryover amount calculated for individual years, at the pre-tax WACC applying for the third access arrangement period

· permit the Commission to exercise its discretion in choosing whether to apply any negative amounts from one access arrangement period to the next [Multinet clause B7.2(a)(9); TXU B7.2(a)(10)].

Envestra is required to amend its proposed Revisions (for both Victoria and Albury) to:

- **clarify in clause B7.2(c)(2) that, in carrying over an accrued negative amount from one year to the next, the negative amount will be multiplied by the pre-tax WACC applying to Envestra for the third access arrangement period;**

- **reinstate its earlier proposed clauses 7.2(c)(3) and (4), to permit the Commission to exercise its discretion in choosing whether to apply any negative amounts from the one access arrangement period to the next.**

Envestra is required to amend its proposed Revisions for both Victoria and Albury to:

- **in clause B7.2(b)(6)(A), clarify that the operating expenditure benchmark for the first year of the next access arrangement period will be set with regard to actual operating expenditure in the penultimate period of the previous access arrangement period and the assumed efficiency gain between the penultimate and final periods embodied in the operating expenditure benchmarks.**

- **in clause B7.2(b)(6)(B), clarify that at the regulatory review for the fourth access arrangement period there will be an adjustment to the regulatory asset base to take account of the difference between forecast and actual capital expenditure in the last year of the second access arrangement period.**

- **add a clause describing the mechanism for adjusting the expenditure benchmarks in the second access arrangement period to take account of growth in calculating the efficiency carryover amount for the third access arrangement period. This should also specify the fixed expenditure amounts per connection and the benchmark connection numbers set out in this report;**

- **add a clause describing the mechanism for adjusting the expenditure benchmarks for the second access arrangement period to take account of changes in scope in calculating the efficiency carryover amount for the third access arrangement period; and**

- **add a clause clarifying that the efficiency carryover amount will be calculated as the net amount of the efficiency gains (or losses) relating to capital and non-capital expenditure.**

Each of the distributors is required to amend their efficiency carryover fixed principles to clarify that the formula for calculating the efficiency carryover is subject to the Commission being satisfied that the service levels and scope of renewal works expected at the start of the access arrangement period have been delivered.

Multinet is required to give effect to its foreshadowed amendment to its proposed fixed principle that provides for the use of the CAPM to be locked in for the third access arrangement period only.

TXU and Multinet are required either to:

- **delete the proposed fixed principle requiring the continued use of the capital asset pricing model (CAPM) for 30 years; or**

- **revise the fixed principle to provide for the use of the CAPM to be locked in for the third access arrangement period only.**

Each of the distributors is required to amend its proposed fixed principle such that:

- **any outstanding capital costs at the end of 2007 that were approved under the OIC to be included in the capital base;**

- **reference tariffs for the third access arrangement period to reflect the cost associated with functions that relate to operating expenditure that was approved under the OIC; and**

- **reference tariffs for the third access arrangement period to reflect any residual correction for over- or under-recovery of revenue or operating expenditure over the period to the end of 2007, pursuant to clause 14 of the OIC.**

Each of the distributors is required to delete the proposed fixed principle allowing it to recover prudent and efficiently incurred costs associated with the implementation of FRC that it has not been able to recover through another mechanism.

Each of the distributors is required to delete the proposed fixed principle related to the recovery of costs associated with retailer of last resort obligations.

Each of the distributors is required to delete their proposed fixed principle allowing them to delete one or more of the fixed principles to reflect amendments to the Gas Code.

Part B

STATEMENT OF REASONS

1 BACKGROUND

1.1 Introduction

The major natural gas distribution pipeline networks in Victoria are currently subject to Access Arrangements that set out the terms and conditions upon which third party users and prospective users can obtain access to the services of those pipelines. On 17 December 1998, the Essential Services Commission's (the Commission's) predecessor – the Office of the Regulator-General – approved the existing Access Arrangements that apply separately to each of the three distributors operating gas distribution networks in Victoria.[5]

On 2 April 2002, the Commission received proposed Revisions to the existing Access Arrangements and Access Arrangement Information from the following entities operating gas distribution networks in Victoria:

- Multinet Gas (DB No.1) Pty Ltd and Multinet Gas (DB No.2) Pty Ltd (trading as 'Multinet Partnership');
- TXU Networks (Gas) Pty Ltd (formerly known as Westar); and
- Envestra licensed as Vic Gas Distribution Pty Ltd (formerly known as Stratus Networks).

On 8 April 2002, the Commission also received from Envestra proposed Revisions to the existing Access Arrangements and Access Arrangement Information in relation to its Albury distribution system.[6]

Under the provisions of the *National Third Party Access Code of Natural Gas Pipelines* (the Gas Code), the Commission is required to decide whether to approve or to not approve the Revisions proposed by each gas distributor to its existing Access Arrangements. The approved Revisions are expected to apply from 1 January 2003 for a period of five years. The Commission's decision to approve or not approve the proposed Revisions must be made within six months of the receipt of the proposed Revisions, unless it gives notice of its intention to extend the decision making period pursuant to the Gas Code.[7]

---

5 The 1998 Decision was made pursuant to the provisions of the *Victorian Third Party Access Code for Natural Gas Pipelines* (the Victorian Gas Code). The Victorian Gas Code has since been superseded by the *National Third Party Access Code of Natural Gas Pipelines* (the Gas Code), which now provides the framework for third party access to natural gas pipeline services in Victoria and other relevant jurisdictions.

6 In January 2002, the relevant State and Federal ministers under the *Gas Pipelines Access Act 1998* consented to cross-vesting jurisdiction to the Commission in relation to certain matters relating to the Albury Distribution System. While the Commission now has regulatory responsibility for access matters, the NSW legislation and licensing arrangements continue to apply under the regulatory control of IPART.

7 Specifically, under section 2.22 of the Gas Code, the Commission may extend the time taken to make its decision by periods of up to two months on one or more occasions provided it publishes in a national newspaper notice of the decision to increase the period.

1.2 The statutory framework underpinning this review

In determining whether or not to approve the gas distributors' proposed Revisions, the Commission is required to have regard to the provisions contained in the Gas Code, made pursuant to the *Gas Pipelines (Victoria) Act 1998*.

In addition, the gas industry in Victoria is regulated pursuant to the *Gas Industry Act 2001*, and currently also under the *Victorian Gas Industry Tariff Order 1998* (the Tariff Order). As Envestra's Albury gas distribution system is located (at least in part) in New South Wales, the *Gas Supply Act 1996* (NSW) is also relevant. The regulatory framework for gas distribution in Victoria and Albury is discussed further below.

1.2.1 Gas Code requirements

The Gas Code establishes a national access regime that applies to natural gas (distribution and transmission) pipeline systems. The Gas Code requires service providers to lodge Access Arrangements with the relevant regulator setting out the terms and conditions (including tariffs) under which they will provide third party access to their users and prospective users.

In Victoria, the Commission is the relevant regulator for gas distribution pipelines while the Australian Competition and Consumer Commission (ACCC) is responsible for regulating gas transmission pipelines.[8] It is also the relevant regulator for the purposes of assessing Envestra's proposed Revisions for Albury, given it was recently cross-vested to Victoria from New South Wales.

The Gas Code provides the detailed regulatory principles and processes underpinning the Commission's assessment of the gas distributors' proposed Revisions.

Under the provisions of the Gas Code, the Commission is required to decide whether to approve or not approve the Revisions proposed by each of the gas distributors to their existing Access Arrangements. In making its decision, the Commission may approve the proposed Revisions only if it is satisfied that the Access Arrangement as revised would contain the elements and satisfy the principles set out in sections 3.1 to 3.20 of the Gas Code. It must also take the following into account:[9]

(a) the Service Provider's legitimate business interests and investment in the Covered Pipeline;

(b) firm and binding contractual obligations of the Service Provider or other persons (or both) already using the Covered Pipeline;

(c) the operation and technical requirements necessary for the safe and reliable operation of the Covered Pipeline;

(d) the economically efficient operation of the Covered Pipeline;

8 The ACCC is currently in the process of assessing Revisions to the existing Access Arrangements applying to the Victorian gas transmission pipeline system as submitted by GasNet.

9 Section 2.24 of the Gas Code.

(e) the public interest, including the public interest in having competition in markets (whether or not in Australia);

(f) the interests of Users and Prospective Users;

(g) any other matters that the Relevant Regulator considers are relevant.

Once approved, the Access Arrangements as revised will establish the terms and conditions for third party users to gain access to the services offered by gas distribution pipeline owners and operators in Victoria for the five-year period commencing 1 January 2003.

The Gas Code also sets out the process the Commission is required to follow in deciding whether to approve or not approve the proposed Revisions. This is further discussed below.

1.2.2 Other relevant legislation affecting Victorian Access Arrangements

In addition to the legislation outlined above, the gas industry in Victoria is also subject more broadly to the provisions of the *Gas Industry Act 2001* (including provisions of the Tariff Order made pursuant to this Act) and the *Gas Safety Act 1997.*

The Gas Industry Act provides for the Tariff Order to confer functions and powers on the Commission relating to the regulation of gas distribution tariffs and charges. The Tariff Order also sets out a number of fixed principles that the Commission must have regard to in deciding price regulation arrangements for the 2003-07 access arrangement period. These fixed principles are part of the Victorian gas distributors' existing Access Arrangements.

In addition, Division 2, Part 3 of the Gas Industry Act requires that gas distributors in Victoria hold a distribution licence in order to provide services by means of a distribution pipeline. The Commission is responsible for licensing the Victorian gas distributors.

The Commission is permitted to impose such licence conditions as determined by it including, amongst other things, conditions requiring licensees to enter agreements on specified terms or terms of a specified type, and to observe specified industry codes and rules.[10]

Currently, each of the distributors has a distribution licence in respect of their Victorian gas networks that requires compliance with the Gas Distribution System Code, the Retail Code and all guidelines applicable to the licensee and published by the Commission under section 13 of the *Essential Services Commission Act 2001*.

[10] Sections 28 and 29 of the *Gas Industry Act 2001*.

In particular, the Gas Distribution System Code sets out minimum standards for operating and using a gas distribution system, including requirements for installing and maintaining connections and metering installations, disconnections and reconnections, and for providing metering data. It also sets out the minimum terms and conditions (other than tariffs) for gas distribution services.

Currently, each of the distributors' Access Arrangements have incorporated by reference the terms and conditions set out in Chapters 10-15 and Schedules 1 and 3 of the Gas Distribution System Code as relevant terms and conditions for the supply of reference services.

Under the *Gas Safety Act 1997*, each gas distributor is required to submit to the Office of Gas Safety (OGS) a plan setting out its management policies and procedures relating to gas safety. The OGS is responsible for overseeing and administering gas safety standards in the industry, and for approving and auditing each gas distributor's compliance with its own safety plan.

In the course of this review and in preparing this Final Decision, the Commission has liaised with OGS on matters of mutual relevance, including service and safety issues and expenditure requirements over the forthcoming regulatory period.

1.2.3 Other relevant legislation affecting Albury's Access Arrangements

The Commission notes that the responsibility for assessing Envestra's Albury Access Arrangements was only recently cross-vested to Victoria in January this year. Shortly thereafter, Envestra submitted its proposed Access Arrangement Revisions to the Commission for approval.

The effect of cross-vesting limited regulatory jurisdiction to the Commission is that the Albury distribution system remains subject to the NSW legislation and licensing arrangements in so far as they apply to those parts of the system located in New South Wales.

Whilst the Commission is required to undertake the assessment of Envestra's proposed Albury Access Arrangement Revisions under the Gas Code, NSW legislation and licensing arrangements continue to apply.

The *Gas Supply Act 1996* (NSW) establishes the statutory basis for the regulation of gas supply and distribution in New South Wales. Its objectives include encouraging the development of competitive markets for gas, regulating gas supply and distribution in a manner that promotes customer choice, and promoting safe gas use.

Parts 2 and 3 of the Act deal with distribution authorisations and licences respectively. Under section 9, a distributor must be authorised under Part 2 to supply or distribute natural gas using a distribution pipeline. Authorisation can be obtained for either reticulation or supply.

The Commission understands that Envestra's intention is to merge the Access Arrangements for both its Victorian and Albury networks. However, the Gas Code does not currently appear to provide for two covered pipelines to be covered by the one Access Arrangement. As a result, Envestra has indicated that it has sought to replicate (as far as possible) the same provisions in its Access Arrangements for both Victoria and Albury arrangements.

IPART is responsible for granting applications for authorisations and licences. An authorisation or licence allows a distributor to distribute gas in a prescribed geographical area, subject to the conditions contained in the Gas Supply Act (NSW) and any regulations made under it. Additional conditions may also be set out in a schedule to the authorisation or licence, and may include mandatory compliance with guidelines, ongoing compliance with technical or prudential criteria, a requirement to hold certain insurance, reporting requirements, or any other condition IPART may impose from time to time (providing the condition is consistent with the Act).

In this Final Decision, the Commission has sought to where appropriate under the decision making framework of the Gas Code to provide consistently for Envestra's Victorian and Albury Access Arrangement Revisions.

1.3 The conduct of this review

In view of the tight timelines provided for consultation and decision-making under the Gas Code, in early 2001, consistent with the provisions of the Gas Code, the gas distributors and a number of other interested parties requested that the Commission conduct early consultation on a number of the substantive issues related to the review of proposed Access Arrangement Revisions. A summary of the consultation undertaken prior to receiving the gas distributors' proposed Revisions is provided in Appendix A.

The Gas Code sets out the process that the Commission is required to follow in deciding whether to approve or not approve the proposed Revisions. This includes requirements for the Commission to:

- inform persons with a sufficient interest in the matter and advertise the receipt of the gas distributors' proposed Revisions and invite submissions in response to those Revisions;
- issue a Draft Decision that has regard to any submissions received by the due date and that either proposes to approve the Revisions or proposes not to approve Revisions and states the amendments (or nature of amendments) that are required in order for the Revisions to be approved;
- provide copies of the Draft Decision to distributors and to certain other persons and invite submissions on its Draft Decision and consider any such responses in its Final Decision;
- the distributors may at this point re-submit the Revisions so as to incorporate or substantially incorporate the amendments specified in the Draft Decision. The Commission notes that the distributors have to some extent submitted such amendments in response to a number of aspects of their proposed Revisions, notably the terms and conditions;

- issue a Final Decision that either approves the Access Arrangement Revisions or does not approve the Access Arrangement Revisions, and states the amendments (or the nature of amendments) that are required in order for the Revisions to be approved;[11]
- allow distributors at least 14 days to submit amended Revisions to the Access Arrangement that incorporate the amendments or nature of amendments required in the Final Decision; and
- issue a further final decision (or Final Approval) that either approves the distributors' amended Revisions, or drafts and approves its own amended revisions to the Access Arrangement.

Appendix A provides a detailed overview of the consultation process undertaken by the Commission to date in assessing the proposed Revisions. In summary, this has included a preliminary consultation process undertaken prior to the receipt of the distributors' proposed Revisions, the release of a Summary Paper (April 2002), Draft Decision (July 2002) and this Final Decision (October 2002). It has also involved the consideration of various submissions received from distributors, customers and other interested parties in response to each of the documents. Each of these papers and submissions (excluding any confidential material) is available on the Commission's website.

1.4 The purpose of this report

This report sets out the Commission's Final Decision in relation to the proposed Revisions. It has been prepared on the basis of the distributors' proposed Revisions and accompanying Access Arrangement Information, and the further submissions, information and amendments provided by distributors and submissions by other interested parties. It also incorporates the Commission's own analysis as well as the comments made by other interested parties.

In summary, the Commission has decided to not approve the gas distributors' proposed Revisions and has set out the nature of amendments that the Commission requires before it will approve them. This report sets out the relevant issues, information and the analysis underpinning the Commission's Final Decision not to approve the proposed Revisions.

In response to this Final Decision, the Commission now requires each of the distributors to submit amended Revisions to their Access Arrangements that incorporate the amendments or nature of amendments specified by the Commission in this report. Distributors are required to provide their amended Revisions by **COB Wednesday 6 November 2002**. These should be forwarded electronically to:

gas.review@esc.vic.gov.au

---

11 This Final Decision constitutes this step.

If approved, the Access Arrangements as further revised will establish the terms and conditions for third party users to gain access to the services offered by gas distribution pipeline owners and operators in Victoria and Albury for the five-year period commencing 1 January 2003. At this stage, the Commission would anticipate releasing its Final Approval of distributors' amended Revisions by the end of November 2002.

1.5 Structure of this report

This Final Decision is structured as follows:

- **section 2** sets out the Commission's reasoning in relation to a number of issues related to the proposed services policies. These matters including the definition of reference services, the terms and conditions applying to those services, service standards (including reliability, and unaccounted for gas) and the incentives that apply to achieve certain standards through guaranteed service level payments; the arrangements applying to non-reference services, and extensions and expansions policies;
- **section 3** sets out the Commission's reasoning in relation to the various components used to determine the total revenue requirement. This revenue requirement is meant to reflect an estimate of the efficient cost of providing the regulated services over the period, plus an increment relating to any efficiency gains made during the current regulatory period (if appropriate). The Gas Code envisages that the efficient cost of providing the regulated services is determined using the methodology that is commonly referred to as the 'building block' approach. This approach involves determining the total revenue with reference to the forward looking benchmarks of operating expenditure, the regulatory asset base (adjusted for capital invested during the current regulatory period), regulatory depreciation, a return on capital invested (including capital invested during the period less depreciation) and an efficiency carryover. Forecasts of demand over the regulatory period are also important in determining the revenue to be made over the period.
- **section 4** presents the Commission's Final Decision in relation to the proposed Revisions with respect to a number of reference tariff policy issues including the form of price control and reference tariffs to apply in the 2003-07 access arrangement period. The proposed reference tariffs reflect the total revenue requirement (discussed in the previous section) and need to comply with certain fixed principles that are set out in the distributors' Access Arrangements. It also presents the Commission's conclusions in relation to the X factors that are to apply over the 2003-07 access arrangement period, given the assumptions adopted in relation to the various revenue components outlined in section 3.
- **section 5** examines a number of other issues related to the proposed Revisions including a number of fixed principles that have been proposed by distributors to apply beyond the 2003-07 access arrangement period, the proposed Revisions submission and Revisions expiry dates, queuing policy, capacity management and trading policy.

2 SERVICES

2.1 Definition of reference services

2.1.1 Background and distributors' proposals

Section 3.2(a) of the Gas Code requires Access Arrangements to include a description of one or more services that a service provider will make available to users or prospective users, including:

- one or more services that are likely to be sought by a significant part of the market; and
- any service or services which in the relevant regulator's opinion should be included in the services policy.

The Gas Code defines 'services' to be 'haulage services', 'right to interconnect' and 'services ancillary to the provision of such services'.

The reference service defined in each distributor's existing Access Arrangement is the basic gas haulage service. The tariffs for this service, in turn, are broken down into Tariff V (volume) and Tariff D (demand). For Tariff V customers, the reference service includes connection to the system and provision of a meter (although a surcharge may be levied if the connection fails the economic feasibility test). The reference service for Tariff D customers includes only the use of the shared network.

Schedule 2 of the *Victorian Gas Industry Tariff Order 1998* (the Tariff Order) currently also prescribes prices for certain 'scheduled excluded distribution services' including meter disconnection, meter removal for debt, disconnection of supply, meter testing and Tariff V connections that exceed the 20-20 rule. These provisions will cease to have effect on 31 December 2002.

In consultation prior to this review, the Commission expressed the view that it may be desirable for distributors to include as reference services in their proposed Access Arrangements any services that are sought by a significant part of the market such as those currently prescribed in the Tariff Order[12] for special meter reading and meter testing at the customer's request.[13] It also expressed the view that, rather than including them under the weighted-average price cap, charges for such (ancillary) reference services would ideally be set at the start of the regulatory period and simply adjusted for inflation over the regulatory period.[14] It proposed deriving a revenue requirement that reflected the cost of providing all reference services (including ancillary services), and then calculating the X factors for the standard transportation service on the basis of the overall revenue requirement less the revenue expected from these ancillary services. It noted that such a regulatory approach would provide the distributors with greater flexibility to determine the charges for such services.[15]

2.1.2 Distributors' proposals

Each of the distributors' proposed Revisions retain gas haulage (or transportation) as the principal reference service as well as the scope of the existing reference service. That is, they include the provision of a meter and service for Tariff V customers, but Tariff D customers pay separately for these assets. The distributors have also generally retained the same basic tariff structure for these services, although TXU has proposed some modifications to facilitate transition of existing Tariff V customers to Tariff D. Issues associated with tariff structures are discussed in section 4.3.

Each of the distributors has also nominated the following three residential customer ancillary reference services (as outlined in table 2.1):

- meter and installation testing;
- disconnection; and
- reconnection.

Consequently, the reference services being approved by the Commission are the basic haulage services described above and the ancillary services set out in table 2.1 and which are described as ancillary reference services.

---

12 Office of the Regulator-General, Consultation Paper No. 1, May 2001, p.16; Further Guidance to Gas Distributors, December 2001, p.10.

13 Office of the Regulator General, Position Paper, 2003 Gas Access Arrangements Review, September 2001, p.16

14 Op. cit., Position Paper, p.14

15 ibid. It would permit greater flexibility as there would be no strategic incentive associated with allocating shared costs between transportation and ancillary services.

TABLE 2.1
DISTRIBUTORS' PROPOSED ANCILLARY REFERENCE SERVICES[a]

Distributors	Meter & installation testing	Disconnection	Reconnection
Envestra (Victoria & Albury)	Typically involves installation of 'check meter' and testing of installation for soundness.	Turning off service valve at Meter Installation, with or without a locking device and or inserting a wad in pipework downstream of the isolation valve, and/or removal of meter.	Involves restoring a disconnected connection, including purging of the gas installation and relighting appliances where applicable.
Multinet	On-site test or at NATA accredited laboratory	Removal of a meter at a metering installation; or Use of locks or plugs at a metering installation; or Excavating and shutting the service tee in the street.	Involves restoring a disconnected connection, including purging of the gas installation and relighting appliances where applicable: between 9.00am and 5.00pm on business days; or at any other time.
TXU	On-site test or at NATA accredited laboratory	Removal of a meter at a metering installation; or Use of locks or plugs at a metering installation; or Excavating and shutting the service tee in the street.	Involves restoring a disconnected connection, including purging of the gas installation and relighting appliances where applicable: between 9.00am and 5.00pm on business days; or at any other time.

a Envestra has one charge for disconnection and reconnection (but disconnection excludes excavation and shutting off at the tee in the street), whereas both TXU and Multinet have different charges depending on the type of disconnection performed and time of the reconnection.

The disconnection and reconnection services relate to services that are provided to retailers to assist the retailers' debt management practices particularly where customers have not paid accounts. The distributors do not levy a separate 'monopoly' charge for new customers connecting to the system in addition to any 'surcharge' that may be payable.[16] The issue of surcharges is discussed in section 0.

The distributors did not include special meter readings as proposed ancillary reference services. Under the Retail Gas Market Rules, the distributors are required to provide special meter readings together with other services associated with full retail competition (FRC). The prices for these services are to be set pursuant to a Governor Order in Council made under section 68 of the *Gas Industry Act 2001*.

16 The connection service provided by the distributors to new customers does not include turning on gas at the meter and lighting appliances (which the distributors refer to as 'turn on' in their proposed Revisions). Two of the distributors have noted that, if requested, they do provide the 'turn on' service for new connections and charge for the service. However in most instances, the customer's gas plumber provides this service (email from J. Bull (Multinet), 17 September 2002 and B. Frewin (TXU) 16 September 2002). As the service is contestable, there is no reason to regulate the fee that distributors charge.

2.1.3 Draft Decision

In the Draft Decision, the Commission proposed to approve each distributor's proposed reference services for the next regulatory period on the basis that they appeared to include the services that were likely to be sought by a significant part of the market. As noted above, while the Tariff V service includes the provision of a meter and service pipe, the distributors may in some circumstances be entitled to levy an additional charge for customer connections. Formally, this charge is referred to as a surcharge, and the rules for levying the surcharge are part of the distributors' extensions and expansions policies (discussed in section 2.7). In contrast, Tariff D customers are required to pay separately for their meter and other connection assets. The issues associated with these charges are discussed in section 2.2.

Prior to the Draft Decision, one retailer (Energex Retail) queried whether there was a need to continue the monopoly provision of meter services. In particular, it noted that there might be an argument for removing the distributors' existing monopoly for basic gas meters prior to 2007 if Government's full retail contestability reform objectives are successful.[17] However, in the Draft Decision the Commission noted that under the Victorian Government's arrangements for implementing full retail contestability (FRC), gas distributors will remain responsible for providing meters for Tariff V customers for an initial period of three years from the start of FRC. The Government has also foreshadowed that it will undertake a review of the exclusivity of gas trading arrangement functions, including meter provision, during the next regulatory period. Accordingly, any decision to introduce competition in the provision of meters to Tariff V customers would not be likely to be implemented until after the end of the 2003 regulatory period.

In the Draft Decision, the Commission also proposed to approve the distributors' proposed ancillary reference service. In relation to the charges for these services, it accepted the 2003 prices for these services but required the distributors to amend their proposed Revisions to provide for ancillary reference charges to be escalated by CPI over the period (discussed in section 4). As noted in consultation prior to this review, the Commission had regard to the revenue associated with these services when setting the price controls for the distributors' transportation services. The Commission adopted Envestra's sale forecasts for these services over the period, and adopted its own assumptions about sales of these services for TXU and Multinet. These assumptions were reflected in the financial models that the Commission placed on its website on 12 August 2002.[18]

2.1.4 Responses to Draft Decision

None of the distributors or any other party raised any issues associated with the definition or regulatory treatment of ancillary reference services in their formal responses to the Draft Decision. AGL pointed out an error in Multinet's proposed prices – that Multinet accepted (discussed in section 4).[19]

---

[17] Energex Retail, Response to gas distributors proposed Revisions, 19 April 2002, p.2.

[18] The models are included at: http://www.esc.vic.gov.au/gas.php@pageid=433.htm .

[19] AGL, Response to the Draft Decision, 7 August 2002, p.3; Multinet, Response to the Draft Decision, 7 August 2002, p.10.

However, in response to a query from the Commission, both TXU and Multinet questioned the relevance of providing revenue forecasts for ancillary reference services for the assessment of the reference tariffs for reference services (and, implicitly, the means of assessing ancillary reference tariffs that was adopted in the Draft Decision). Both TXU and Multinet submitted an identical comment:

> With regard to the request for forecast quantities for Ancillary Reference Services which you say are needed for input into the model used to determine the X-factor, [TXU/Multinet] contends that Ancillary Reference Services do not impact on the X-factor in relation to Reference Services. [TXU/Multinet] has not included forecast quantities of Ancillary Reference Services in its forecasts for Reference Services and does not consider it necessary to provide the forecasts quantities requested. [TXU/Multinet] also notes that as a practical matter reliable forecasts are not available.[20]

2.1.5 Further analysis

The Commission remains of the view that the distributors' proposed reference services represent those services that are likely to be sought by a significant part of the market and meet the requirements of the Gas Code. However, it notes that there are some differences amongst the distributors in relation to the precise definition of each of the proposed services, albeit that the differences are not sufficiently material to warrant requiring an amendment. Nevertheless, should the distributors choose to standardise their definitions of these services, then the Commission would welcome such changes and be likely to adopt them when making its final approval of the distributors' Revisions.[21]

Regarding the regulatory treatment of ancillary reference services, the Commission is somewhat surprised by TXU and Multinet's late remarks about the relevance of providing demand forecasts for ancillary reference services. In consultation undertaken prior to this review, the Commission clearly articulated that its proposed approach to determining the reference tariffs for these services would be to derive a revenue requirement covering all reference and ancillary reference services, and then deduct the revenue expected from ancillary reference services to determine the revenue requirement applicable to the reference (transportation) services. As a result, the revenue expected from ancillary reference services has a direct impact on the assessment of price controls for the reference (transportation) services.

The Commission foreshadowed this approach in two consultation papers released in 2001.[22] In its response to the Position Paper, United Energy (on behalf of Multinet) merely noted that it 'was not in a position to provide forecasts of expected revenues for these services at that time'.[23]

20 Email from J. Bull (Multinet),17 September 2002 and B. Frewin (TXU), 16 September 2002.

21 There is variation amongst the distributors' prices for these services, as well as in the number of charges specified for each service (for example, the number of different disconnection options that are priced). This issue is discussed in section 4.

22 Consultation Paper No. 1, p.27; Position Paper, p.14.

23 United Energy, Response to Position Paper, 26 October 2001, p.14.

In consultation undertaken prior to the distributors' submitting their proposed Revisions, TXU submitted indicative financial forecasts of its proposed reference and ancillary services that adopted the Commission's proposed approach for these services and specifically noted that:

> Forecast revenue information [for ancillary reference services] has been provided in the financial model provided by separate submission.[24]

As also noted above, the Commission made an assumption about the revenue from these services in the Draft Decision, which was reflected in the financial models that it placed on its website. Lastly, as the charges for ancillary services will formally be reference tariffs, the proposed charges are required (in the regulator's opinion) to meet the principles in section 8 of the Gas Code.[25] The regulatory approach proposed by the Commission to apply to these services is a simple means of ensuring this outcome. Neither TXU nor Multinet has proposed an alternative approach for demonstrating that these charges comply with the principles in section 8 of the Gas Code. In addition, neither has presented an argument as to how it is possible to comply with these principles (in particular, section 8.2) in the absence of a forecast of revenue from these services. Accordingly, the Commission has retained its proposed regulatory approach for these services.

There are two implications of this regulatory approach, namely that:

- the expenditure forecasts factored into reference tariffs should include the cost of providing these services; and
- it requires a forecast of sales of these services over the next regulatory period.

These matters are discussed in sections 3.3 and 3.9, respectively.

2.1.6 Final Decision

The Commission remains of the view that the distributors' proposed reference and ancillary reference services appear to include the services that are likely to be sought by a significant part of the market, and should therefore be approved. Whilst it notes that there are some differences in relation to definitions of the proposed services applied by each distributor, the Commission would welcome the distributors working together to standardise their definitions of these services prior to submitting their final amended Revisions to the Commission for approval.[26]

---

24 TXU, Response to the Position Paper, 26 October 2001, p.11.

25 Section 3.4.

26 The prices for these services as well as in the number of charges specified for each service vary across distributors (for example, the number of different disconnection options that are priced).

2.2 Prices for non-reference services

2.2.1 Background

Non-reference services are those services that do not have tariffs specified in the Access Arrangements. Under the Gas Code, the terms and conditions that apply to these services – including tariffs – may be negotiated between the relevant parties, with the option of binding arbitration by the Commission in the event of an unresolved dispute.

The Commission has previously expressed the view that it would be desirable for the distributors' Access Arrangements to include a set of high-level pricing principles for non-reference services.[27] To a large extent, the need to provide such guidance for negotiated services depends on the number and type of monopoly services included as reference services and ancillary reference services. Accordingly, the Commission suggested that an alternative approach to specifying pricing principles for non-reference services would be to require that services such as those that have in the past been the subject of disputes between users and distributors be included as reference services.[28]

One of the non-reference services the Commission has previously expressed concern about is the provision of connection assets to Tariff D customers. The prices these customers pay for connecting to the system are negotiated as non-reference services on a case-by-case basis. The Commission has raised concerns over the lack of transparency in the principles used to determine these charges and invited distributors to include pricing principles for such charges in their proposed Revisions. It also noted that, irrespective of the legal framework under which these charges are determined, the assessment of reference tariffs for reference services requires an assumption about the pricing for these services. This is because the assessment of reference tariffs requires a view about how much of the costs that are shared between reference and non-reference services should be factored into reference tariffs.

---

27 Such high-level principles could, for example, include a requirement that prices be based on the incremental cost of providing each service.

28 Op. cit., Position Paper, p.18.

2.2.2 Distributors' proposals

None of the distributors included pricing principles for Tariff D connections or for any other non-reference services in their proposed Revisions.[29] Instead, TXU and Multinet noted that guidance on the price for the service in the event of a dispute over such negotiated services should be limited to those matters listed in section 6.15 of the Gas Code. TXU and Multinet also argued that pricing principles for non-reference services are not warranted on the basis that there have been no disputes to date in relation to such services.[30]

2.2.3 Draft Decision

As noted above, in the Draft Decision the Commission considered that the distributors' proposed reference services appeared to include all of the services that are likely to be sold to retailers in material quantities over the next regulatory period and as a consequence did not consider pricing principles would have as significant a role to play.

However, the Commission noted concerns about the lack of transparency in the pricing principles being applied by some of the distributors with respect to Tariff D customer charges for the provision and maintenance of their dedicated assets. It also noted that it currently has the power to set a 'fair and reasonable' charge for this service under the Gas Distribution System Code,[31] and that it intended to retain this requirement in the arrangements to apply from 1 January 2003.[32] It also stated that in the absence of including pricing principles for Tariff D connection charges in the distributors' Access Arrangements, it would use its power to issue guidelines to resolve its concerns about the current arrangements.

The Commission noted that while it would develop such guidelines independently of the current review, an assumption about the pricing of Tariff D connection services is required in order to assess reference tariffs. In particular, it requires an assumption about whether (and, if so, to what extent) joint or common costs would be recovered from non-reference services, and so should not be included in reference tariffs. In the Draft Decision, it assumed that the charges for the provision and ongoing maintenance of Tariff D connection assets would reflect the marginal cost of providing these services, and proposed that this pricing principle be reflected in the guidelines referred to above. Consistent with this, the Commission intended to include all overheads in reference tariffs and took the distributors' reported operating expenses for 2001 as the starting point for the forward-looking benchmarks. The Commission assumed that these benchmarks included all overheads and noted that it would test the veracity of this assumption prior to the Final Decision.

---

29 It may not be necessary for the parties to negotiate all of the terms and conditions of supply of a non-reference service on a case-by-case basis. With respect to services provided to retailers, once a charge is agreed, the terms and conditions (including in relation to payment) apply. These are discussed further section 2.3.

30 TXU also incorrectly claimed that prices for such connections are determined in accordance with the economic feasibility provisions under section 8.16 of the Gas Code

31 Clause 3.3(a)(1) of the Gas Distribution System Code. Compliance with the Gas Distribution System Code is a condition of each of the Victorian distributors' licences.

32 Section 3.1, Draft Gas Distribution System Code, Version 8.0.

No change was required to the relevant provisions in the distributors' proposed Revisions.

2.2.4 Responses to Draft Decision

TXU and Multinet argued that it is difficult for the Commission to justify a guideline on charges to Tariff D customers for the provision and maintenance of their dedicated assets given the small number of new connections each year and the absence of past disputes.[33] TXU also noted that it would be reasonable to assume that Tariff D customers can negotiate their own arrangements with service providers. It also requested that the Commission reconsider whether it was appropriate to require that no overheads should be allocated to these services.[34] Envestra argued that the Commission's proposed approach blurs the distinction between the Gas Code and licensing requirements, giving rise to uncertainty and regulatory risk, and that any guideline should be made available prior to the Final Decision.[35]

In contrast, a retailer supported the Commission's proposed approach:

> We note that the Commission has concurred with the proposals submitted by the [distributors] to dispense with the inclusion of pricing principles for non-reference services. We support the Commission's intention to retain its power under the Gas Distribution System Code to determine what is a 'fair and reasonable' price in the absence of pricing principles. We note also that the Commission intends to issue a guideline describing how it intends exercising its power to make this decision. AGL looks forward to the publication of these guidelines.[36]

The submission on behalf of the Customer Energy Coalition also supported further guidance being provided on the pricing for these services:

> Tariff D (large) customers are obliged to 'negotiate' the terms and conditions for (almost) everything other than gas haulage. However, the ESC is to retain powers to regulate 'connection charges' for Tariff D consumers, and will issue Guidelines compelling the [distributors] to publish 'pricing principles' for non-reference' services provided to Tariff D consumers – for both of which Tariff D consumers will, no doubt, be thankful.[37]

2.2.5 Further analysis

The Commission remains concerned about the pricing principles being applied by some of the distributors for Tariff D connections, as well as the overall lack of transparency associated with the determination of these charges. In response to the Draft Decision, Multinet commented that it has included principles for determining Tariff D charges in its proposed Revision. However, the only reference in its Revisions is clause 5.1.3, which states:

---

33 Op. cit., TXU, Response to Draft Decision, p.14; Multinet, Response to the Draft Decision, p.11.
34 Envestra, Response to Draft Decision, 9 August 2002, p.24.
35 ibid.
36 Op. cit., AGL, Response to Draft Decision, p.3.
37 Pareto Associates (for the Customer Energy Coalition), Response to the Draft Decision, 23 August 2002, p.48.

> The Service Provider will make Services other than Reference Services available to Users or Prospective Users as agreed or as determined in accordance with section 6 of the Access Code.[38]

The Commission considers that this proposal – together with any other proposal by the distributors during the current review – has done little to ameliorate this concern. Moreover, the Commission does not consider that this matter is immaterial as the service provided to Tariff D customers includes both the provision of the relevant infrastructure as well as its ongoing maintenance over time. Further, TXU's Access Arrangement Information suggests that it had received over $1.1 million for just the ongoing maintenance of this infrastructure in 2000.

Accordingly, in the absence of pricing principles in the distributors' Access Arrangements, the Commission continues to see merit in issuing a guideline under the Gas Distribution System Code specifying how it would exercise its power to determine fair and reasonable Tariff D connection charges. It does not share Envestra's view that such an approach blurs the distinction between regulatory requirements under the Gas Code and distribution licences. Rather, it considers it complements the requirements of the Gas Code and provides for an integrated regulatory framework.

In the Draft Decision, the Commission indicated that an assumption about the pricing of Tariff D connections is necessary in order to assess the reference tariffs – including whether they should recover any shared costs. Settling upon and publishing this assumption now will also assist in ensuring the guidelines the Commission has foreshadowed for these charges are consistent with the assumptions adopted in the assessment of reference tariffs, thus reducing the uncertainty associated with future regulatory decisions. Given the transparency of the Commission's assumptions on this matter, it does not accept Envestra's comment that issuing guidelines about this matter subsequent to the Final Decision will add materially to 'regulatory risk'.

The Commission notes that only TXU commented on the pricing principles for Tariff D connection services proposed in the Draft Decision, but neither it nor other distributors proposed alternatives. Accordingly, in the absence of further proposals by the distributors, the Commission confirms that it will assume that the distributors' charges for the provision and ongoing maintenance of dedicated assets for Tariff D customers reflect the marginal cost of providing those particular assets and undertaking that maintenance (that is, no overheads or margin applied). The Commission has had regard to operating cost benchmarks in assessing whether reference tariffs that have been determined are consistent with this pricing assumption.

The pricing assumption discussed above will be reflected in the guideline for Tariff D connections, to be issued under the Gas Distribution System Code. Subject to this overarching principle, the Commission will adopt a consultative approach to the development of these guidelines.

[38] Multinet, Access Arrangement Revision, Part A.

2.2.6 Final Decision

The Commission does not require any amendments to the distributors' proposed Revisions to deal with the pricing of these services.

As noted above, the Commission will retain its current power under the Gas Distribution System Code (to apply from January 2003) to set 'fair and reasonable' charges for the provision and maintenance of dedicated assets for Tariff D customers, and will issue a guideline to resolve its concerns about the pricing of these services. The Commission has assumed that, in the next regulatory period, the charges for these services will reflect the marginal cost of service provision, and has adopted this assumption in the assessment of the distributors' reference tariffs. This pricing principle will be reflected in the guideline referred to above.

2.3 Terms and conditions

2.3.1 Background

Section 3.6 of the Gas Code requires:

> An Access Arrangement must include the terms and conditions on which the Service Provider will supply each Reference Service. The terms and conditions included, must in the Relevant Regulator's opinion, be reasonable.

In determining whether the terms and conditions contained in the distributors proposed Revisions are reasonable, the Commission is required to take into account the matters listed in section 2.24 of the Gas Code.

In consultation undertaken prior to this review, the Commission expressed the view that the distributors' Access Arrangements should contain a complete set of default contractual provisions. The Commission established a working group (comprising representatives of the distributors, retailers and other interested parties) to review the terms and conditions to apply to reference services from 1 January 2003 with a view to establishing a consistent set of terms and conditions that would be incorporated into the distributors' Access Arrangements.

2.3.2 Draft Decision

In the Draft Decision, the Commission noted that distributors had each proposed terms and conditions that were largely consistent.[39] In addition, the distributors indicated that they had based the proposed terms and conditions largely on the electricity default use of system agreement (EUoS), modified to suit the gas industry circumstances and the existing gas Distribution Tariff Agreements (DTA). The distributors noted that such an approach was intended to 'facilitate ease of commercial management within the converging energy industry'.[40]

As noted in the Draft Decision and consultation undertaken prior to this review, the Commission expressed the view that it considered it to be in the interests of both distributors and retailers that the distributors' proposed terms and conditions contain standard commercial terms, and are sufficiently complete, clear and unambiguous, and practical and workable. It also expressed the view that, consistent with section 2.24, it would be both efficient and in the interests of distributors and retailers that the proposed terms and conditions be as consistent as possible across the gas industry, and further that it would promote competition in both the electricity and gas markets if there was also some degree of consistency in the terms and conditions applied by distributors and retailers in both of those sectors.

In the Draft Decision, the Commission identified a number of matters associated with the distributors' proposed terms and conditions that it proposed should be amended in order to give effect to issues and comments made by retailers and other interested parties, and where it considered that there were grounds for adopting an alternative approach. It also expressed the view that the precise wording to give effect to the Commission's proposed amendments was a matter that would be best progressed by the distributors and retailers continuing to work together. To this end, the Commission proposed to reconvene the Terms and Conditions Working Group (comprising retailers, distributors and other interested parties that initiated the proposed terms and conditions) to further discuss the detailed approach to dealing with these matters and work towards developing a standardised and consistent set of terms and conditions across distributors for the Final Decision. To facilitate this process, the Commission indicated that it would prepare a draft revised set of the terms and conditions that could form the basis for further discussion.

2.3.3 Responses to Draft Decision and further analysis

Following the release of the Draft Decision, the Commission wrote to each of the distributors, retailers and other interested parties inviting them to form part of the Terms and Conditions Working Group. In doing so, the distributors advised that they intended to revise the proposed terms and conditions in light of the Draft Decision and would provide this to the Commission and other interested parties in advance of the Working Group meeting.

---

[39] Envestra's proposed terms and conditions for Albury include a number of differences that reflect Albury Gas Company's obligations under relevant NSW legislation.

[40] Multinet, Access Arrangement Information, 2 April 2002, p.10; TXU, Access Arrangement Information, 2 April 2002, p.6; Envestra, Access Arrangement Information (Victoria), 2 April 2002, p.59.

In response to the Draft Decision, the Commission received a number of submissions commenting on the amendments required to the terms and conditions as part of the Draft Decision. In addition, the distributors submitted an amended revision to their proposed terms and conditions, which gave effect to a number of the Commission's required amendments.[41]

Following the Terms and Conditions Working Group meeting (on 5 September 2002), the distributors then submitted another set of amended revisions to the terms and conditions reflecting the agreement reached on a number of the remaining issues of concern to both distributors and retailers. As a result, the number of remaining issues related to the terms and conditions has substantially narrowed since the release of the Draft Decision. As a consequence, the Commission requires amendments to be made with respect to only a few remaining clauses, which are discussed below. Appendix B provides a more detailed discussion of the issues in relation to the distributors' proposed terms and conditions and the extent to which they have been addressed.

Definitions and interpretation

Clause 1.1 of the distributors' proposed terms and conditions provides that certain terms are defined with reference to the definitions clause in the Access Arrangements glossaries.

In the Draft Decision, the Commission noted that there were differences in the definitions used by the distributors in their Access Arrangements and proposed that the distributors amend their terms and conditions to:

- include a consistent set of definitions across distributors; and
- give effect to the Commission's decision on reference services.

In the Draft Decision, the Commission also noted that Multinet's definition of distribution services excludes connection for Tariff D customers, whereas TXU excludes Tariff D and Tariff M connection. In Envestra's proposed Revisions for both Victoria and Albury, the term 'distribution service' does not appear to contain any exclusions with respect to connections.

The distributors noted that as the definitions in the terms and conditions are incorporated by reference to the Principal Arrangements, they wished to retain consistent definitions across the Principal Arrangements and the terms and conditions. They have proffered that they would accommodate any request from a user for a fully self-contained list of definitions. The Commission did not receive any further submissions from retailers requesting a consistent set of terms and conditions. The Commission accepts the distributors' position on this matter.

41 These amended revisions were provided to the Commission on 7 August 2002, and made available on the Commission's website.

With respect to the distributors' approach in relation to the Commission's decision on reference services, the Commission notes that each of the distributors' Access Arrangements glossaries contain a consistent definition of distribution services. However, the Commission notes that the distributors have proposed different approaches with respect to identifying 'services other than reference services'. While the approach taken by Multinet and Envestra (in their Schedules 2 and 3 respectively) to identify such services appears reasonable, TXU has, in its Schedule 3, included meter installations and testing, disconnection and reconnection services, which it has also listed as ancillary reference services in Schedule 1 of Part A of its Access Arrangements. The Commission therefore requires TXU to amend Schedule 3 of its terms and conditions to remove services that it has identified as ancillary reference services.

AMENDMENT REQUIRED

TXU is required to amend Schedule 3 of its proposed terms and conditions to remove services that it has identified as ancillary reference services.

Customer relationship

Under clause 3 of the distributors' proposed terms and conditions, the distributor will supply distribution services to the retailer in respect of the retail customers, except where the retailer notifies the distributor that the customer is not a haulage customer or the distributor and the customer have entered into a haulage agreement.

In the Draft Decision, the Commission required each of the distributors to amend clause 3 of their proposed terms and conditions to include:

- a resolution clause where the customer enters into separate agreements with a retailer and distributor; and
- a clause precluding the distributor's terms and conditions from operating retrospectively.[42]

With respect to the first issue, each of the distributors advised that they have accepted this proposed amendment and have amended clause 3(b) of their proposed terms and conditions to provide that:

> If at any time a Customer contracts for the same Distribution Services from both the Distributor and the User, the Distributor and the User will use their reasonable endeavours to implement the contractual relationship desired by the Customer.

In regard to the second issue, the Commission remains of the view, having regard to section 2.24(b) of the Gas Code, that the distributors should be required to include a clause preventing the terms and conditions from operating retrospectively.

42 In proposing this amendment, the Commission noted that a similar clause currently exists in the EUoS [clause 3(c)].

AMENDMENT REQUIRED

Each of the distributors is required to amend clause 3 of their proposed terms and conditions to prevent the terms and conditions from operating retrospectively.

Invoicing and payment

Clause 7.4 of the distributors' proposed terms and conditions establish procedures and obligations relating to invoicing and payment for distribution services provided by the distributor to the retailer.

In the Draft Decision, the Commission considered that there would be merit in aligning payment terms – including the timing of invoices and payments – between gas distributors and retailers with those for electricity and proposed that each of the distributors should amend clause 7.4 accordingly.

In response to the Draft Decision, the distributors argued:

- the Distribution Tariff Agreements reflect current gas industry practice of issuing a mid month and a monthly invoice; and
- removing a distributor's ability to invoice on a mid month and end month basis would have significant negative cash flow implications for the distributors (and require a working capital allowance).

The distributors amended their terms and conditions to provide that they will use best endeavours to invoice on the same business day each month, mid month invoices will be calculated based on actual metering data, and allowing retailers 10 days to pay invoices, regardless of whether it is mid-month or end-month.

In response to the proposed terms and conditions, TXU Retail and Origin Energy again sought to provide that 10 *business* days be allowed for the payment or disputing of invoices, consistent with that provided in the EUoS. The Commission considers that it is reasonable to require the terms and conditions to specify business days.

In terms of aligning billing procedures between gas and electricity, the Commission has considered the views put forward by distributors and retailers, particularly concerning costs. In the absence of information from the retailers that a change to the mid monthly billing arrangements will result in savings to consumers, the Commission accepts the distributors' revisions to clause 7.4 is in relation to invoicing.

However, the Commission considers, having had regard to section 2.24 (a) and 2.24(f) of the Gas Code, that the distributors should be required to amend clause 7.4(i) to permit users to pay invoices received within 10 *business* days after the day on which the invoice is received.

AMENDMENT REQUIRED

Each of the distributors is required to amend clause 7.4(i) of their proposed terms and conditions to permit users to pay invoices within 10 *business* days of the day on which an invoice is received.

Disputed invoices

Clause 7.7 of the distributors' proposed terms and conditions sets out procedures for users and distributors to follow regarding a disputed invoice. In the Draft Decision, the Commission noted various issues raised by retailers in relation to this proposed clause, including the nature of payments to be made to the distributor in the event of a disputed invoice.

Following the Draft Decision, a number of retailers argued that this clause should be amended to provide that the retailer would pay an amount reasonably agreed by the parties or the undisputed part of an invoice, but not 80 per cent of the amount of the previously undisputed invoice as provided for in clause 7.7(c)(2), owing to practical difficulties and seasonal variation in invoices.

Having regard to section 2.24(a) and 2.24(f) of the Gas Code, the Commission considers it reasonable that the distributors amend the terms and conditions to delete clause 7.7(2) and require that only the amount of the invoice that is not in dispute be paid. In coming to this conclusion, the Commission notes that clause 7.7(e) provides for the disadvantaged party to recover the difference in the amount already paid and the amount determined to be payable, plus any interest accruing, following resolution of the dispute.

AMENDMENT REQUIRED

Each of the distributors is required to delete clause 7.7(c)(2) of their proposed terms and conditions and require that only the amount of the invoice that is not in dispute is to be paid.

Adjustment of invoices

Clause 7.5 requires an incorrect charge in an invoice to be altered to correct an error and is based on Clause 7.6 of the EUoS. Reatailers have argued that clause 7.5(c) should provide that an adjustment to an invoice should not be permitted if it is the result of an error by VENCorp in providing data to the distributor, as is provided for in clause 7.5(a)(3).

Clause 7.5(c) in the proposed terms and conditions provides for an exception to adjustments in respect to defective meter readings, errors in billing of gas consumption and differences in the actual and estimated readings, obtained after the invoice is issued, where a retailer is precluded by the regulatory instruments from recovering from its customer (except where the incorrect charge arises as a result of an act or admission of the retailer). In the Commission's view, having regard to sections 2.24(a) and 2.24(f) of the Gas Code, it would be appropriate for clause 7.5(c) to explicitly exclude the application of clause 7.5(a)(3).

AMENDMENT REQUIRED

Each of the distributors is required to amend clause 7.5(c) of their proposed terms and conditions to explicitly exclude the application of clause 7.5(a)(3).

GSL payments

Clause 7.6 of Multinet and TXU's proposed terms and conditions set out the distributors' and retailers' rights and obligations in relation to GSL payments as well as a Schedule defining the proposed GSL events (ie. definitions, payments conditions and amounts).

In the Draft Decision, the Commission took the position that GSL events would be most appropriately included in the Gas Distribution System Code, requiring Multinet and TXU to amend clause 7.6 of their proposed terms and conditions accordingly. In addition, it was required Envestra to insert a new clause into its terms and conditions to give effect to the GSL scheme, as proposed by Multinet and TXU and amended by the Draft Decision. Each distributor has made these amendments.

The Commission has noted that the Gas Distribution System Code does not currently apply in respect of Envestra's Albury network (by virtue of the fact that it is also regulated under NSW legislation).[43] As a result, the Commission proposed that, in the absence of superior available arrangements at this time, Envestra should include a provision in its terms and conditions for Albury, defining the GSL events and payments as set out in the Final Decision (see section 2.6). The Commission also proposed that Envestra insert a clause in its terms and conditions for Albury, providing for the clause to cease to have effect in the event that a similar provision in the Gas Distribution System Code purports to give effect to the GSL scheme in relation to Envestra's Albury network.

[43] This issue is discussed in section 2.6.5 of the Final Decision.

AMENDMENT REQUIRED

Envestra is required to amend its proposed terms and conditions for its Albury network to:

- **define the GSL events and payments applicable to the Albury network as set out in the Final Decision; and**
- **provide for the clause to cease to have effect in the event that a similar provision in the Gas Distribution System Code purports to give effect to the GSL scheme in relation to Envestra's Albury network.**

Liabilities and indemnities

Clause 13 deals with warranties, indemnities and admissions, the procedure for notifying third party claims, and the preservation of certain statutory provisions.

In the Draft Decision, the Commission proposed that the distributors be required to amend clause 13.1 of their proposed terms and conditions to provide that nothing in clause 13 prevents the GSLs from operating. The Commission also required distributors to include clauses dealing with liability to supply and non-operation of limitations of liability, based on clauses 13.2 and 13.3 of the EUoS.

In response, the distributors amended their proposed terms and conditions to include a new draft clause 13.1(b) to provide that nothing in clause 13 prevents the GSLs from operating. However, they also advised that they were not prepared to amend clause 13.2(a) and 13.2(b) as proposed by the Draft Decision, arguing that any such clause would need to:

- be confined to limit their liability to the performance or non performance of distribution services, under normal contracted supply terms;
- require the user to consult with the customer regarding risk and require the customer to implement appropriate risk mitigation measures; and
- abate the distributor's liability to the extent that the user contributed to the customers claim.

The distributors proposed the following amendment:

> Without limiting any other legal liability of a Service Provider, subject to the exclusions provided in sections 213, 233(1) or 233(3) of the GIA and the Gas Safety Act, the Service Provider shall indemnify the User against any:
>
> (b) Claim against the User by a Customer for breach by the User of any conditions, warranties or terms implied by Part V of the Trade Practices Act 1974 and equivalent State legislation in respect of the Supply by the Service Provider in relation to that Customer:
>
> (1) to the extent that the breach has not occurred as a result of the acts or omissions of the User;

(2) where the User has by its conduct and in its Retail Contract with that Customer limited or excluded its liability to that Customer for breach of any of the conditions, warranties or terms implied by Part V of the Trade Practices Act 1974 and equivalent state legislation into that Retail Contract to the maximum extent permitted by that Act and by the Regulatory Instruments;

(3) where the User has, at the Service Provider's request, delivered to the Customer any information published by the Service Provider concerning the inherent limitations in the quality and reliability of the Supply;

(4) provided the User has not agreed to supply to the Customer Distribution Services in excess of the standard of Distribution Services to be supplied by the Service Provider to the User under this Agreement; and

(5) provided that the User has consulted with the Customer as to the implementation of appropriate risk mitigation measures to minimise the potential for any Claim by the Customer under this clause, and the User:

(i) implements and maintains such measures; and

(ii) uses all reasonable endeavours to ensure that the Customer implements and maintains such measures.

(c) The User must demonstrate to the Service Provider its compliance with its obligations under clauses 13.2(b)(2), 13.2(b)(3), 13.2(b)(4), and 13.2(b)(5) on reasonable request of the Service Provider from time to time.

(d) The liability of the Service Provider under this clause 13.2(b) shall be reduced to the extent that the User has caused or contributed to the Claim.

(e) A Claim under this clause 13.2(b) will be a Claim for the purposes of clause 13.8(a).

Retailers and distributors further discussed this issue at the Working Group meeting on 15 August 2002, with AGL raising concerns that the distributors proposed amendment – particularly clauses 13.2(b)(1) and 13.2(b)(5) - diverted unnecessarily from the arrangements in place for electricity in removing liability from the distributor.[44]

With respect to AGL's concerns over clause 13.2(b)(1), the Commission notes that the distributors have altered the original drafting of the subclause and that it is now consistent with the EUoS. However, the Commission shares AGL's concerns with respect to clause 13.2(b)(5), in that it proposes to place onerous obligations upon retailers in relation to issues that are most appropriately managed by the distributor. Having regard to sections 2.24(a), 2.24(c) and 2.24(f) of the Gas Code, the Commission requires distributors to delete clause 13.2(b)(5) from their proposed terms and conditions.

44 AGL, Comments on Redrafted Terms and Conditions, 23 August, 2002, p.5.

AMENDMENT REQUIRED

Each of the distributors is required to delete clause 13.2(b)(5) of their proposed terms and conditions.

2.4 Reliability

While the Gas Distribution System Code specifies a number of specific service-related obligations for the distributors,[45] it does not set out requirements or targets for the reliability of the gas distribution networks (that is, those that relate to interruptions to supply). Instead, it sets out a number of general requirements for distributors, for example, to use reasonable endeavours to maintain the capability of the distribution system and to develop maintenance programs.

Throughout this review process, the Commission has highlighted the importance of ensuring that the distributors and customers have unambiguous expectations of the service levels to be provided over the regulatory period. The need for such expectations reflects the interests of users in receiving reliable and safe gas services. It also provides the Commission with a point of reference for assessing the distributors' proposed reference tariffs, and for considering whether cost reductions over the regulatory period have been achieved at the expense of reliability.

The Commission has acknowledged that current levels of aggregate network reliability – largely driven by the safety-related requirements of the Office of Gas Safety – appear to be relatively high. The distributors' initial submissions pointed to these high levels of performance against existing reliability standards and, for example, Envestra argued that the benefits to customers from an increase in service reliability would not exceed the costs.[46]

Accordingly, the Commission remains of the view that the distributors should be required to continue to provide a level of overall supply reliability (as measured by outage events, customers interruptions, leakage surveys and reports) consistent with that provided over the past three years. It has previously indicated that it will establish a working group to advance the measurement of reliability over the next regulatory period, and for additional reliability-related information to be collected. For example, the Commission has noted that there may be merit in distinguishing some performance targets for high, medium and low-pressure parts of the network. This enhanced measurement will assist the Commission to assess whether the distributors' performances over the next period reflect their current performance as well as provide better information to enable it to judge whether it may be appropriate to introduce further incentive mechanisms to encourage distributors to improve or maintain their level of reliability.[47]

45 These include the requirement to maintain minimum pressure levels (clause 2.1(b)) and requirements with respect to the accuracy and testing of meters (chapter 8).

46 Envestra, Access Arrangement Information, 2 April 2002, p.13.

47 Draft Decision, p.20.

In the Draft Decision, the Commission considered two specific reliability-related incentive mechanisms, which were the arrangements applying to unaccounted for gas, and the requirement to make payments to customers who receive service below guaranteed service levels. These two mechanisms are discussed in turn.

2.5 Unaccounted for Gas

2.5.1 Background

Unaccounted for gas (UAFG) refers to the quantity of gas that has been measured as having entered the system, but has not been measured as having been delivered to a customer. UAFG can arise because of leakage from the gas distribution system, meter error, theft, inaccuracy in the conversion from quantity of gas measured to energy (reflecting discrepancies in temperature, pressure, heating value, altitude or the gas compressibility factor), and a number of other causes.

The Gas Distribution System Code currently sets out benchmarks for UAFG for the Victorian gas distributors.[48] Under the current incentive arrangements, retailers initially bear the cost for all UAFG. However, if actual UAFG is greater than the benchmark, then the distributor pays an amount to the relevant retailer or retailers equal to the cost of the additional gas lost, and vice versa where UAFG is lower than the benchmark (this process is referred to below as the 'annual reconciliation'). In this way, the distributors bear the cost associated with gas losses in excess of the benchmarks and benefit from gas losses that are below the benchmarks, thus providing the distributors with a commercial incentive to optimise gas leakage. The process for giving effect to the annual reconciliation payments is currently set out in the Distribution Tariff Agreements between the retailers and distributors, and the proposed process going forward is set out in the distributors' proposed terms and conditions (see Appendix B).[49]

The current UAFG benchmarks referred to above express the UAFG as a percentage of gas deliveries, with separate benchmarks applying in respect of volumes delivered from the high-pressure system and deliveries through the low-pressure system.[50] In addition to the incentive arrangements for UAFG outlined above, the Gas Distribution System Code requires distributors to use reasonable endeavours to ensure that the quantity of UAFG in their systems is less than the prescribed benchmark.[51]

48 Gas Distribution System Code, Schedule 1, Part C. Envestra's (Albury) UAFG benchmarks are currently set out in its Access Arrangement Information. The Commission has previously expressed the view that the benchmarks should continue to be specified in the Gas Distribution System Code (Essential Services Commission, Position Paper – Proposed Revisions to Regulatory Instruments, February 2002, p.10).

49 VENCorp has been contracted by the parties to calculate the UAFG settlement value.

50 The high-pressure network is defined as customers with an annual usage in excess of 250 TJ, while customers with an annual usage less than 250 TJ are categorised as being in the medium to low-pressure network.

51 Gas Distribution System Code, clause 2.1(g).

In Access Arrangements applying to gas distributors in other jurisdictions, a forecast of UAFG is normally included in the distributors' operating cost benchmarks, and the distributors are required to purchase sufficient gas to cover UAFG. However, the effect of the arrangements applying in other jurisdictions and Victoria is substantially the same – distributors are rewarded if they outperform against the UAFG assumptions, and are penalised financially if they under-perform against those assumptions.

In consultation prior to the Draft Decision, the Commission emphasised the desirability of retaining the current incentive arrangements for UAFG.[52] However, it also noted its intention to update the UAFG benchmarks, which were developed in 1998 and prior to the installation of meters at the transfer points between the transmission system and the distribution systems.[53]

2.5.2 Distributors' proposals

In their proposed Revisions, each of the distributors proposed retaining the current UAFG incentive arrangements, but did not propose to update the benchmarks on the basis of actual performance. While Envestra and TXU proposed merely retaining the current benchmarks,[54] Multinet proposed varying the original benchmark to correct for an error it considers was made when the current benchmarks were set.[55]

The distributors' existing and proposed UAFG benchmarks for volumes delivered from the high pressure (above 250TJ/a) and low-medium pressure (below 250TJ/a) parts of the networks are set out in table 2.2.

TABLE 2.2
DISTRIBUTORS' EXISTING AND PROPOSED UNACCOUNTED FOR GAS BENCHMARKS

	Current benchmark (% of deliveries)		Proposed benchmark (% of deliveries)	
	< 250 TJ/a	> 250 TJ/a	< 250 TJ/a	> 250 TJ/a
Envestra – Victoria	2.9%	0.3%	2.9%	0.3%
Envestra – Albury	4.1%	0.1%	4.1%	0.1%
Multinet	2.7%	0.3%	3.13%	0.3%
TXU	2.8%	0.3%	2.8%	0.3%

52 Op. cit, Position Paper, p.10.

53 Office of the Regulator-General, Access Arrangements for Multinet, Wester and Stratus: Final Decision [1998 Final Decision], October 1998, pp.174-5. In a submission to the Office, VENCorp emphasised that the current UAFG benchmarks 'must only be considered the "best currently available" [as] the figures come from historical data in GASCOR UAFG reports based on Longford to consumer data, they are not based on [custody transfer meter] to consumer meter data' (VENCorp, Submission to Proposed Amendment to the Unaccounted for Gas Table in the Victorian Gas Distribution System Code, 1999, p.1). This approximation reflected the fact that these benchmarks were determined prior to the installation of meters at the transfer points between the transmission and distribution systems (completed in 1999).

54 Envestra, Access Arrangement Information, pp.27-28; TXU, Access Arrangement Information, pp.26-27.

55 Multinet, Access Arrangement Information, p.71.

The distributors' proposed terms and conditions sets out a process for annually reconciling and settling payments to be made between distributors and retailers as a result of performance against UAFG benchmarks. This involves VENCorp calculating the reconciliation amount in accordance with a confidential VENCorp Connection Deed, and notifying the distributors and retailers of the amounts that must be paid.[56]

2.5.3 Draft Decision

In the Draft Decision, the Commission remained of the view that it was appropriate to update the UAFG benchmarks in the Gas Distribution System Code to reflect current practice, particularly given that the existing benchmarks had been developed in 1998 and prior to the installation of meters at the transfer points between the transmission system and the distribution systems.

The Commission expressed the view that the relevant issue is whether the UAFG benchmarks that are called up by the terms and conditions represent an unbiased forecast of UAFG over the period. It noted that there are now a number of years of data on measured flows into the separate distribution networks, which was not available when the original benchmarks were derived. As a result, it did not consider that the original benchmarks could be argued to have a greater level of precision than a benchmark based upon actual measured flows.

The Commission proposed to update the UAFG performance benchmarks in the Gas Distribution System Code to apply from 1 January 2003 at the arithmetic average of performance over the years 1999 to 2001 inclusive, with those annual amounts calculated on a consistent basis. It noted that this would provide a reasonable proxy for current practice and, in turn, an unbiased forecast of future levels (assuming the distributors' current practices remain unchanged).

In relation to the UAFG incentive arrangements, the Commission expressed the view in its Draft Decision that the current mechanism should continue to apply and also noted concerns expressed about the lack of transparency associated with the current process. In particular, one concern was that the method used to determine outturn performance may have a material impact on the effectiveness of the incentives provided to optimise gas losses, and that transparency in any assumptions used and in the distributors' performances would be more consistent with the interests of users and the public interest.

Accordingly, the Commission proposed that the methodology required to calculate the UAFG amount and reconciliation payments should also be specified in the Gas Distribution System Code. It also proposed to require distributors to provide information annually to the Commission on their UAFG performance, which could then be published. In determining the methodology to be specified in the Gas Distribution System Code, the Commission indicated that it would liaise closely with VENCorp, as well as other interested parties.

It also noted that a consequential amendment would need to be made to the distributors' proposed terms and conditions to recognise these revised arrangements.

---

[56] See section 2.3 of Part C of each of the distributors' proposed terms and conditions.

2.5.4 Responses to Draft Decision

With the exception of the caveats set out below, all of the distributors accepted the Commission's proposals with respect to UAFG. Multinet noted only that it expected the actual results for 1999 to 2001 to be adjusted for 'gross abnormalities'. It noted that current performance would imply a benchmark of approximately 3.2 per cent.[57] Envestra noted that it considered the 1999 data to be unreliable, and that the 2000 and 2001 results were more reliable – which were very close to the original benchmarks.[58] In accepting the Commission's proposals, TXU drew the Commission's attention to a material development since it submitted its proposed Revisions. It noted that there has been an unmetered flow into one of its networks that has implied that its actual performance was worse than previously thought once the impact of the unmetered flow (which has now been shut off) is taken into account.[59] It also noted that the new information on UAFG also has implications for the capital investment program that it has proposed. This latter issue is discussed in section 3.4.[60]

A number of retailers supported the Commission's proposals in the Draft Decision. For example, AGL commented:

> AGL supports the Commission's decision in regard to UAFG. Where actual data drawn from the experience of UAFG wash-ups is available, it makes little sense for distributors to recover costs for UAFG based on theoretical benchmarks derived from Gascor's experience as a bundled utility.[61]

It also commented that when the Commission is deciding on actual UAFG performance, it should obtain information from both retailers and the distributors. TXU Retail also commented:

> We agree that there is a need to reflect the UAFG calculation methodology and risk allocation prescribed in the Gas Distribution System. It is also desirable that the UAFG calculation methodology which exists currently in a variety of documents be consolidated. We do not support an approach by which the methodology is set out in the VENCorp Connection Deed, given that retailers are not a party to this Deed.[62]

2.5.5 Further analysis

In light of the submissions noted above, the Commission remains of the view that it should update the UAFG benchmarks in the Gas Distribution Code to reflect current performance.

---

57 Multinet, Response to the Draft Decision, p.32.
58 Envestra, Response to the Draft Decision, p.24.
59 TXU, Response to the Draft Decision, p.15.
60 TXU, Response to the Draft Decision, p.5.
61 AGL, Response to the Draft Decision, p.4.
62 TXU Retail, Response to the Draft Decision, p.2.

Regarding the method that will be used to determine current performance, the Commission remains of the view that a simple average of performance over the first period is a reasonable starting point, although it accepts that it may need to apply some caution in interpreting the results. The Commission accepts that it should adjust for factors that have had a material effect on measured UAFG in the current period and that are not expected to be present in the next ('gross abnormalities') – with the unmetered flow into TXU's system being one such factor. It will also need to take a view on the reliability of the data that is used, noting Envestra's concerns with the reliability of 1999 results, and TXU's concerns expressed in its proposed Revisions.[63]

All of these matters will be considered further as part of its consultation on the new UAFG benchmarks. However, the objective of the exercise is clear – that is, to establish the best, unbiased measure of performance at the end of the current regulatory period (taking account of any 'gross abnormalities' noted above). The issues noted above will be assessed against this objective.

Given the submissions summarised above, the Commission also remains of the view that it should also set out the methodology for determining UAFG performance and the reconciliation amount in the Gas Distribution System Code.

Following the release of this Final Decision, the Commission will update the Gas Distribution System Code to apply from 1 January 2003 in accordance with the consultation processes provided for in that Code. The Commission also notes that the distributors' proposed terms and conditions have been amended to reflect these new arrangements (see Appendix B).

2.5.6 Final Decision

The Commission will revise the Gas Distribution System Code to apply from 1 January 2003:

- revise the existing UAFG benchmarks to reflect current practice;
- set out the methodology to be used to calculate UAFG performance and the UAFG reconciliation payments; and
- require the distributors to provide the Commission with information on their UAFG performance and reconciliation payments on an annual basis, which will then be published.

[63] TXU, Access Arrangement Information, p.27.

2.6 Guaranteed service level payments

2.6.1 Background

In consultation undertaken prior to this review, the Commission raised the issue of whether the gas distributors should be provided with additional incentives with respect to service quality and reliability. It identified a number of possible incentive mechanisms that could be introduced, including payments for guaranteed service levels (GSLs) and adjusting the price controls to reflect actual versus targeted service performance.

TXU and Multinet offered some support for such a scheme. Multinet emphasised that the focus of such a scheme should be to provide incentives for gas distributors to ensure the level of service delivered to individual gas consumers is not materially less than the high level of reliability delivered, on average, by the network as a whole.[64] A number of other interested parties also supported the concept of introducing GSLs, including the Energy and Water Ombudsman of Victoria and BHP-Billiton Petroleum.[65] Envestra opposed such a scheme in its submissions.

2.6.2 Distributors' proposals

Multinet and TXU proposed four GSLs in their proposed Revisions – that is, where there would be a payment to customers where the GSL was not met.[66] The nature of the proposed GSLs, together with the proposed thresholds and payment levels, is summarised in table 2.3 below. In contrast, Envestra did not propose a GSL scheme in its Revisions for its Victorian or Albury networks, arguing that there is insufficient evidence at this point in time of the benefits to customers from GSLs to warrant the cost of introducing GSLs.[67]

TABLE 2.3
MULTINET AND TXU'S PROPOSED GSLS

Area of service	Level of service to incur GSL payment	Level of GSL payment
Appointments	More than 15 minutes late for appointment with a residential customer.	$50 per event.
Connections	Failure to connect a residential customer within 2 days of agreed date.	$80 per day ($240 max)
Repeat interruptions	More than 6 unplanned interruptions to a residential customer in a calendar year resulting from faults in the distribution system.	$100 for each subsequent event in that calendar year.
Lengthy interruptions	Interruption of more than 12 continuous hours to a residential customer's supply as a consequence of a fault in the distribution system.	$80 per event.

64 Multinet, Access Arrangement Information, p.16
65 BHP-Billiton Petroleum, Submission to Position Paper, November 2001.
66 These are set out in Schedule 3 of Multinet's proposed terms and conditions and Schedule 4 of TXU's proposed terms and conditions.
67 Envestra, Access Arrangement Information (Victoria), p.13 and Access Arrangement Information (Albury), p.10.

Under the GSL scheme proposed by Multinet and TXU:

- payments would be made to residential customers only;
- exclusions would apply in relation to certain events outside their control (ie. force majeure, events occurring in a natural gas installation, events occurring in the transmission system or natural gas production); and
- payments to affected customers are to be made through retailers as per the process set out in the distributors' proposed terms and conditions.[68]

Regarding the cost associated with such a scheme, Multinet and TXU noted that there is very little rigorous information available on the historical incidence of the proposed GSL events, and that assumptions were required. This issue is discussed further in section 3.3.

2.6.3 Draft Decision

In the Draft Decision, the Commission considered first, whether Envestra should also be required to introduce a GSL scheme, and secondly, whether the design of the scheme proposed by TXU and Multinet is appropriate.

Regarding the first of these matters, the Commission had regard to the provisions in the Gas Code in section 2.24, the objectives in section 8.1, the provisions dealing with incentive mechanisms (sections 8.44-8.46) as well as the views and preferences expressed by users. On balance, it concluded that the introduction of such a scheme by all of the distributors would be consistent with the requirements of the Gas Code. However, the Commission concluded that the Gas Distribution System Code would be a preferable mechanism to give effect to the GSL scheme given that GSLs represents a service level commitment to end-user customers rather than retailers.[69]

Regarding the form of the GSL scheme, the Commission accepted the coverage of the GSL scheme, noting that the defined events and its restriction to residential customers was appropriate, at least for the next regulatory period. However, the Commission required three changes to the proposed schemes, which were:

- to change the threshold for payment for multiple interruptions from 6 events to 3 events per annum, but also to reduce the payment for additional interruptions from $100 to $50; and
- to limit the scope of exclusions applicable to the 'time taken to restore supply', 'appointments' and 'connections' GSLs.

68 See section 7.6 of both Multinet and TXU's proposed terms and conditions.

69 As the Gas Distribution System Code does not apply in Albury, a different mechanism would be required for that business. This issue is discussed further below.

2.6.4 Responses to Draft Decision

Envestra reiterated its opposition to the introduction of GSLs, noting that 'the Commission has not presented any evidence that the significant costs incurred in implementing the scheme for electricity have resulted in a net benefit or that service levels of electricity distributors have improved as a result'. It also noted that the Commission appeared to assume that 'what is good for electricity is good for gas', and that the Commission has not canvassed alternative means of ensuring service quality is maintained. It also noted that no allowance was made in its reference tariff proposals for the cost of introducing GSLs, and that if forced to implement a GSL scheme, it would not be in a position to do so by 1 January 2003.[70]

Energex argued that GSLs – or some equivalent instrument – should be expanded to provide retailers with compensation for non-delivery of distributor services:

> …non-performances by distributors under their access arrangements impose additional costs on retailers and have important competition effects. … Energex suggests that at the very least, the final contracts between distributors and retailers define a mechanism whereby Retailers are able to seek redress for any additional costs as a result of the distributors non-delivery of services (ie. metering data, billing information, CATS services).[71]

A gas customer proposed that the GSLs should be expanded in relation to new connections to include a requirement to:

- answer requests for connection in writing, explaining the customers' rights and obligations in plain English;
- respond with a quote within 10 working days of the customer fulfilling its obligations under the Gas Distribution System Code;
- to offer a rebate to 'pioneer' customers where connection involves a body corporate or strata title;[72] and
- explain in writing a failure to meet the Gas Distribution System Code requirement to use reasonable endeavours to connect a customer within 20 business days.[73]

The Customer Energy Coalition noted a number of unsatisfactory aspects of the proposed scheme, but:

> [d]espite the reservations outlined … it does appear (from the outcomes in both UK and Australia) that distribution business managers do focus on activities affecting any form of structured, publicly accountable service performance obligation. And many consumers can recount 'horror' stories that show distributors need extra stimulus to do a lot better.[74]

---

70 Envestra, Response to Draft Decision, 9 August 2002, p.25.

71 Energex, Response to Draft Decision, 17 July 2002, p.2.

72 A 'pioneer' scheme refers to a scheme whereby if a customer sponsored an initial extension of a network, then customers who subsequently make use of that infrastructure would be required to rebate some of the initial customer's contributions.

73 Name Withheld, Response to Draft Decision, 5 August 2002, pp.1-2.

74 Pareto Associates (for the Customer Energy Coalition), Response to the Draft Decision, p.52.

Regarding the cost of meeting GSL payments, Multinet included additional information on the frequency of multiple outages and concluded that, by changing the threshold, the Commission had significantly under-estimated the cost of these payments. It also noted that the data for 2001 – upon which the estimate of the frequency of multiple event payments was based – was a dry year, and so more payments could be expected in normal years.[75] Multinet also cautioned against making direct comparisons between distributors on this measure, given that the primary cause of interruptions in its system is water entering the low-pressure network, and its low-pressure network is twice the size of TXU's.

Regarding exclusions, Multinet disagreed with the Commission's proposal not to exclude upstream events from the 'time taken to restore supply' GSL. It noted that such a fault is beyond its control, could expose it to very large risks, and is inconsistent with other law and the Commission's previous decisions.[76]

TXU directed the Commission to a previous Revision it had made to the information provided on the cost of implementing the GSL scheme, but otherwise did not comment on the proposals contained in the Draft Decision.[77] The issues associated with the cost of the scheme are discussed in section 3.3.

2.6.5 Further analysis

The Commission remains of the view that the introduction of a GSL scheme for all of the distributors (including for Envestra's Albury business) would be consistent with the requirements of the Gas Code. As noted in the Draft Decision, the Commission considers that an incentive for the distributors to avoid incidents of poor service to be in the interests of customers, and is also consistent with the pursuit of economic efficiency and the broader public interest. The Commission also notes the Customer Energy Coalition's support for introducing such a scheme, as well as the strong support provided by Pulse Energy, Energex Retail and others in submissions prior to the Draft Decision.[78]

Whilst Envestra has asserted that there would be 'significant costs to customers in operating the scheme', it has not provided any evidence or even estimates of the cost to support this claim. In contrast, the (revised) estimates of operating the scheme from the other distributors are relatively modest.

---

75 Multinet, Response to Draft Decision, 7 August 2002, p.33.

76 ibid, p.34

77 TXU, Response to the Draft Decision, p.15.

78 Summarised in the Draft Decision, p.26.

The Commission does not concur with Envestra's view that the introduction of a GSL scheme reflects an assumption that 'what is good for electricity is good for gas' and that it has not taken account of the specific characteristics of gas distribution. In particular, it accepted the comments from distributors that the current high levels of reliability at the system-wide level for gas distribution implied that an incentive arrangement on aggregate service levels would not be justified.[79] Thus, what was seen as appropriate for electricity, was not accepted as necessarily being appropriate for gas. Moreover, it is noted that the service incentive arrangements applicable to gas distribution in the UK are very similar to those applicable to electricity distribution, and both of which include a GSL scheme. Thus, it is not clear that there should be a presumption that gas necessarily is different.

Regarding Energex' proposal to apply GSLs to the retailer-distributor relationship, the Commission considers that GSLs (which will be given effect through licence conditions for the Victorian distributors) should only apply to grant rights to end-users, and that Energex's concerns are more appropriately addressed in the contractual terms and conditions (see section 2.3).

Regarding the comments of the customer to extend GSLs to a range of additional connection-related matters, the Commission does not consider, at this stage, that the issues raised are systemic and that an extension of the GSLs would be warranted. Nevertheless, the Commission wrote to distributors requesting responses to the matters raised, which have been posted on the Commission's website.[80] Some of the comments made – such as the role of 'pioneer schemes' – are relevant to the assessment of connection charges (surcharges) for customers. As discussed in section 0, the Commission intends to issue a guideline on this matter, and will consider further the observations made in this submission in that context. As to other issues raised in relation to distributors' performance in undertaking new connections, the Commission will continue to monitor compliance with licence obligations and take such actions as necessary.

The other matters raised related to the change in the threshold for 'multiple interruptions' that the Commission imposed, and the scope of exclusions.

Regarding the threshold for multiple interruptions, the Commission notes that information provided by Multinet suggests that the Commission may have understated the proportion of customers who receive between four and six interruptions, and thus understated the impact of the change in the threshold. Given the Commission's intention to limit the scheme to a modest incentive over the next regulatory period, it considers it appropriate to adopt the threshold originally proposed by Multinet and TXU of six interruptions in the year, but to retain the payment per event adopted in the Draft Decision of $50. The revised information provided by Multinet on this matter also affects the assumption about the expected GSL payments for multiple interruptions. This issue is discussed in section 3.3.

79 Position Paper, pp.11-12.

80 The Commission acknowledges the very comprehensive response provided by Envestra on this matter.

Regarding the breadth of the exemptions, the Commission accepts Multinet's comments about the desirability of excluding the upstream events from the GSL scheme. The Commission did not intend to include upstream events in the class of events for which GSL payments may result, but accepts that this was not clear in it Draft Decision. For the avoidance of doubt, the Commission considers that the following exclusions for the different GSLs are appropriate:

- Appointments – appointments rescheduled by customers are excluded (no other exclusions would apply);
- Connections – no exclusions;
- Repeat interruptions – force majeure, faults on gas installations, transmission faults, upstream faults and third pary events are excluded; and
- Lengthy interruptions – force majeure, faults on gas installations, transmission faults and upstream faults are excluded (third party events are not excluded).

As noted above, TXU and Multinet initially proposed giving effect to the GSL scheme through their proposed terms and conditions. However, as the Commission has indicated that the definition of the GSL events and payments would be more appropriately described in the Gas Distribution System Code, it is necessary to amend their proposed terms and conditions to reflect this as a consequence. This issue is discussed in section 2.3.

The Commission notes that the Gas Distribution System Code does not currently apply in respect of Envestra's Albury network (by virtue of the fact that it is also regulated under NSW legislation). Whilst the Commission understands that it is possible to include the GSL provisions as they apply to Envestra's Albury network in the Victorian Gas Distribution System Code, it is unclear how the Commission would necessarily enforce such provisions. As a result, at this stage, whilst not considered the most desirable means of enforcement, the Commission proposes that Envestra should include a provision in its terms and conditions that defines the GSL events and payments as set out in this Final Decision, thereby making the payment of GSL events a contractual matter between the retailer and the distributor (as originally proposed by Multinet and TXU).

However, the Commission considers that it is still desirable to find an approach to enable the Commission to enforce various provisions in Victorian regulatory instruments as they relate to Envestra's Albury Access Arrangements. Accordingly, it will identify and pursue these alternative options following the release of this Final Decision, in the course of consulting on the amendments to the Gas Distribution System Code. In the interim, it will also require Envestra to insert a clause in its proposed terms and conditions for Albury that provides for the clause to cease to have effect in the event that a similar provision in the Gas Distribution System Code purports to give effect to the GSL scheme in relation to the Envestra's Albury network. This matter is also discussed further in section 2.3.

2.6.6 Final Decision

The Commission will require the distributors to introduce a GSL scheme of the form described in table 2.4.

The Commission will revise the Gas Distribution System Code to give effect to this obligation, and require Envestra to give effect to the same scheme. In relation to applying the GSL scheme to Albury customers, the Commission requires Envestra to give effect to the scheme through a change to its proposed terms and conditions for the Albury network (this required amendment is discussed in section 2.3).

The Commission notes that each distributor has revised their proposed terms and conditions to provide for the introduction of the GSL scheme.

TABLE 2.4
FINAL DECISION: GUARANTEED SERVICES LEVEL THRESHOLDS AND PAYMENTS TO BE INCLUDED IN GAS DISTRIBUTION SYSTEM CODE

Area of service	Level of service to incur GSL payment	Level of GSL payment
Appointments	More than 15 minutes late for appointment with a residential customer[a]	$50 per event
Connections	Failure to connect a residential customer within 2 days of agreed date	$80 per day (subject to a maximum of $240)
Repeat interruption	More than 6 unplanned interruptions to a residential customer in a twelve month period resulting from faults in the distribution system[b]	$50 for each subsequent event in that calendar year
Lengthy interruptions	Gas supply interruption to a residential customer not restored within 12 hours[c]	$80 per event

a Appointments rescheduled by the gas businesses should be counted as missed appointments. Appointments rescheduled by the customer are excluded from payments.

b Excluding force majeure, faults in gas installations, transmission faults, third party events and upstream events.

c Excluding force majeure, faults in gas installations, transmission faults and upstream events.

2.7 Extensions and expansions policy

2.7.1 Background

The Gas Code requires the distributors to include an extensions and expansions policy in their Access Arrangements.[81] The first two components of the extensions and expansions policy are most relevant to the current matter,[82] which are:

- *coverage* – the Access Arrangement needs to contain a decision rule for determining whether an extension to the existing system is to be treated as part of the existing system and hence, covered under the single Access Arrangement; and
- *pricing* – the Access Arrangement needs to state how users will be charged where the provision of their service requires an extension or an expansion.

In its previous consultation papers, the Commission identified a number of distinct matters that would need to be addressed in the distributors' extensions and expansions policies.

81 Section 3.16 of the Gas Code.

82 The other component of the extensions and expansions policy permits the distributors to agree to fund certain projects, subject to agreed terms.

One of the matters that would be covered by the policies is the principle to be used to determine charges for new customers connecting to the system. For new Tariff V customers, the principles in the extensions and expansions policies will determine whether they may be required to pay an additional charge at all to receive the service. For Tariff D customers, the principles in the extensions and expansions policies will determine whether they may be required to pay a charge to connect to the system in addition to their specific assets (the principles for charging for specific assets were discussed in section 2.2).

Another component of the distributors' Access Arrangements that formally will be part of their extensions and expansions policies is the regulatory arrangements to apply to extensions to take gas to towns that currently do not have access to natural gas. The Commission raised a number of issues associated with the regulatory treatment of such projects in a previous matter and early in the consultation process for the current review, in response to which the distributors have made proposals the Commission considers very constructive.

The discussion below first addresses the distributors' proposed coverage rules, and then addresses the specific issues noted above. A number of miscellaneous issues are discussed thereafter. In assessing the distributors' proposed extensions and expansions policies, the general factors in section 2.24 are relevant. In addition, as the second component of the policy deals with pricing, the general objectives in section 8.1 of the Gas Code, as well as the specific provisions dealing with new investment, need to be considered,[83] together with the general factors in section 2.24.

2.7.2 Rule for coverage of extensions and expansions

Section 5.6.1 of the distributors' existing Access Arrangements permit the distributors to have significant extensions excluded from their Access Arrangements and treated as stand-alone systems, where significant extensions are defined as an extension that will service a minimum of 5 000 customers.[84] All non-significant extensions (ie. those not meeting the test described above) are required to be covered by their existing Access Arrangements.

In their proposed Revisions, Envestra and Multinet proposed a change to the treatment of non-significant extensions in order to permit the regulator to agree to a non-significant extension not being covered by the existing Access Arrangement. In contrast, TXU proposed changing the coverage rule to exclude any extension (whether significant or non-significant) unless it was included in the calculation of reference tariffs. In correspondence between the Commission and the distributors prior to the Draft Decision, TXU and Envestra commented that the drafting of section 5.6.1 of their proposed Revisions does not materially alter the effect or intent of the section as it applies in their existing arrangements.

83 Sections 8.15-8.26 of the Gas Code.

84 In order to have a significant extension excluded from the Access Arrangement, the distributor is required to provide the Commission with written notification beforehand. Extensions that were assumed in the calculation of reference tariffs cannot be excluded.

Draft Decision

In the Draft Decision, the Commission referred to the approach to this matter in its 1998 decision, in particular that the rule for determining whether a new extension should be covered automatically involves a trade-off between a number of factors.

It noted that, on the one hand, including all extensions under the one Access Arrangement would minimise administrative costs, reduce the extent to which the method used to allocate costs between different parts of the system is a material concern, and reduce the ability of the distributors to exercise market power where this exists. These matters suggest that wider coverage would be in the interests of users, and have public interest benefits. On the other hand, the Commission noted that the Gas Code envisages that service providers would be able to have the necessity of coverage (and thus regulation) of a new project tested under section 1. Thus, a limit to the automatic coverage of new projects would also have public interest benefits, as well as be in the distributor's legitimate business interest. It noted that the current Access Arrangement provisions were the product of a careful consideration of these factors in 1998, and that its reconsideration of these factors during the current review has led to the same conclusions. That is, for all assets to be treated as part of the existing system, apart from significant projects, as defined above.

The Commission also noted two further matters that it considered supported continuing the current coverage test. First, it noted that one of the advantages of including new projects in the existing Access Arrangements is that this permits the projects to be 'pooled' with the distributors' other projects, thus leading to a substantially lower level of uncertainty over the profitability of projects such as those serving unreticulated townships. This benefit would not be available if projects were undertaken on a stand-alone basis. Second, it noted establishing clear expectations for the next regulatory period about the regulatory treatment of new projects – particularly projects to extend gas to unreticulated towns – will assist to reduce the administrative costs of dealing with these projects. It noted that clarity of the regulatory arrangements would be promoted by a broader coverage of these projects.

With respect to the distributors' proposals, the Commission noted that Envestra and Multinet's proposals were virtually identical to those in their current Access Arrangements, the only change being that the regulator would have the discretion to approve a non-significant project not automatically being covered by the existing Access Arrangements. While the Commission noted that the considerations discussed above would suggest that the distributors should not expect the regulator to agree to such an exemption in the normal course of events, it accepted the proposals on the basis that the flexibility to address circumstances not currently contemplated is appropriate.

In contrast, the Commission noted that, notwithstanding TXU's statements to the contrary, its proposed Revisions would lead to a substantial change to the existing coverage rule, in effect, excluding any new project (irrespective of size) from the existing Access Arrangements that had not been taken into account when assessing reference tariffs. The Commission also noted that the statement that projects included in the calculation of reference tariffs would be covered (which would have a substantive application in the case of TXU) appeared to reflect an assumption that the reference tariffs would be set on the basis of a line-by-line assessment of individual projects, which was not the case. For the reasons discussed above, the Commission proposed to require TXU to amend the coverage clauses in its Revisions to reflect Multinet and Envestra's proposals.

Responses to Draft Decision

In their submissions to the Draft Decision, Multinet noted that the Commission accepted its proposal (but did not comment further on the Commission's conclusions or reasoning).[85] Envestra did not address the issue.

In contrast, TXU reiterated its view that its proposed change to the wording of the existing clause does not materially alter its operation or effect (and noted that it is amenable to continue with the existing clause).[86] However, it also confirmed that the Commission had interpreted correctly the intended operation of its coverage clause.[87]

Further analysis

The Commission confirms the conclusions it reached in the Draft Decision with respect to Envestra and Multinet's proposed coverage rules in their extensions and expansions policies for the reasons summarised above and set out in more detail in the Draft Decision.

With respect to TXU, the Commission remains of the view that TXU has described its proposed clause in a manner that is not consistent with its likely operation, and that the clause proposed is materially different to the equivalent clause in its existing Access Arrangement (clause 5.7.1). The Commission reaffirms its conclusion in the Draft Decision that TXU's proposed clause is inappropriate for the reasons summarised above and set out in more detail in the Draft Decision.

However, it also notes that Envestra and Multinet's proposed coverage clause (accepted above) would offer additional flexibility over the regulatory treatment of non-significant assets that is not present under its existing coverage clause, and should be seen as advantageous to TXU. Accordingly, the Commission invites TXU to replace its proposed coverage clause with a clause identical to that proposed by Envestra and Multinet. Should TXU not choose to take up this option, the Commission considers it appropriate that TXU retain the equivalent clause from its existing Access Arrangement (clause 5.7.1).

85 Multinet, Response to the Draft Decision, p.35.
86 TXU, Response to the Draft Decision, p.38.
87 Email from B. Frewin (TXU), 18 September 2002.

Final Decision

The Commission accepts Envestra and Multinet's proposed Revision relating to the coverage rule in their extensions and expansions policies, but requires TXU's proposed Revisions to be amended either to:

- adopt a clause identical to that proposed by Envestra and Multinet, or to
- replace clause 5.6.1 in its proposed Revisions with the equivalent clause from its existing Access Arrangement (clause 5.71).

AMENDMENTS REQUIRED

TXU is required to amend section 5.6.1 of its proposed Revisions either to:

- **adopt a clause identical to that proposed by Envestra and Multinet, or to:**
- **replace clause 5.6.1 in its proposed Revisions with the equivalent clause from its existing Access Arrangement (clause 5.71).**

2.7.3 Connection charges – application of the economic feasibility test

One of the requirements of an extensions and expansions policy is to record how charges are to be determined for customers where an extension or expansion is required to provide their service. As noted in the Draft Decision, for Tariff V customers, the relevant issue is whether a charge in excess of the reference tariff may be levied in order for them to connect to the system (or substantially change their existing service requirements). For Tariff D customers, the issue is whether a charge in excess of the reference tariff may be levied for the use of the shared system when a customer connects to the network (or changes its existing service requirements).[88]

The basic framework for determining such charges – referred to as surcharges – is the economic feasibility test under the Gas Code.[89] The application of the economic feasibility test in any particular case will depend, in part, upon the assumptions adopted in that analysis, and the Commission has noted that there would be substantial benefits from the adoption of administrative simplifications to the test – particularly where it is applied to small customers.[90]

88 Tariff D customers pay directly for their dedicated connection assets.

89 In broad terms, the Gas Code permits an additional charge (referred to as a surcharge) to be levied where the incremental cost associated with a connection (or change in connection) exceeds the incremental revenue. Capital expenditure financed directly through surcharges cannot be included in the capital base.

90 Office of the Regulator-General, Further Guidance to Gas Distributors, December 2001, p.30.

With respect to small customers, in its earlier consultation papers, the Commission raised concerns with the potential inconsistency between the *20/20 rule* contained in the Gas Distribution System Code and the generic economic feasibility test under the Gas Code. The Commission encouraged distributors to submit principles for Tariff V connection charges that were consistent with the economic feasibility test under the Gas Code, but noted that there is a strong case for adopting a simplified application of the test. The Commission has also noted that it would be highly desirable for the assumptions adopted in the application of the test to be consistent across the businesses.[91]

Each of the distributors proposed using the economic feasibility test in the Gas Code to calculate surcharges for all new customer connections, and dropping the 20/20 rule.[92] While one of the distributors indicated the likely assumptions that it would adopt in applying that test,[93] none proposed a comprehensive set of principles and assumptions. TXU stated that further principles would be unnecessary.[94] However, two of the distributors noted that, in the majority of cases, applying the economic feasibility test for domestic customer connections would not result in a surcharge.[95]

Draft Decision

In the Draft Decision, the Commission accepted the distributors' proposal to adopt the economic feasibility test in the Gas Code as the basis for calculating connection charges for Tariff V customers and surcharges for use of the shared system for Tariff D customers. However, it expressed concern over the distributors' proposal to rely solely on the provisions in section 8.16 of the Gas Code to guide the derivation of surcharges given that the application of this test requires a number of assumptions to be made, the choice of which may materially affect the results.

The Commission also noted that in previous consultation it has proposed retaining the current power in the Gas Distribution System Code to determine fair and reasonable charges for Tariff V and Tariff D connections after 1 January 2003.[96] In the absence of principles being set out in the distributors' Access Arrangements or otherwise approved by the Commission, this clause permits the Commission to decide what is meant by 'fair and reasonable', which would imply deciding upon the appropriate assumptions for use in the economic feasibility test.

The Commission reiterated the view that there would be benefits from administratively simplifying the test, as well as adopting consistent assumptions across the distributors. In the absence of proposals from the distributors to include such arrangements in their proposed Revisions, the Commission indicated that it intended to issue a guideline on the assumptions it considers reasonable in applying the test if called to do so under the Gas Distribution System Code.

---

91 Op. cit., Further Guidance to Gas Distributors, p.30.

92 Envestra, Access Arrangement Information, pp.65-66; Multinet, Access Arrangement Information, pp.8-9; TXU, Access Arrangement Information, pp.4-5. The assessment of surcharges would take place under clause 5.6.2 of the distributors' Access Arrangements.

93 Envestra, Access Arrangement Information, pp.66.

94 TXU, Access Arrangement Information, p.5.

95 Multinet, Access Arrangement Information, p.9; TXU, Access Arrangement Information, p.5.

96 This would be supported by a requirement on the distributors to connect a customer within the minor or infill extension area - see section 3.1(c) of the Draft Gas Distribution System Code, Version 8.0.

The Commission noted that the assumption about how the economic feasibility test would be applied over the regulatory period is necessary to be able to assess the distributors' reference tariffs, in particular, whether a portion of shared costs (like overheads) would be expected to be recovered outside of the reference tariffs. In its assessment of the distributors' reference tariffs, the Commission assumed that the economic feasibility test would be applied in the following manner.

- *Life* – an assumed economic life of 30 years for a residential connection, and 15 years for a commercial connection, in the absence of any strong reason to the contrary;
- *Demand* – for domestic customers, set at the average consumption across the customer group, and for other customers, a forecast of their actual consumption or demand;
- *Discount rate* – set at the implied real pre tax WACC used in the preceding price review (no assumption about inflation should be necessary if the assessment is undertaken in constant prices);
- *Future tariffs* – current tariff, extended forward by the prevailing X factor for the assessment life;
- *Operating costs* – incremental operating costs only – that is, no overheads;
- *Capital costs* – for domestic customers, the actual capital cost of the connection (meter and service pipe) and incremental mains extension (if required), and for Tariff D customers, incremental mains extension (if required) and upstream reinforcement (if required).

Adopting different assumptions about these principles (in particular, the assumption that the capital and operating cost used in the feasibility test would include incremental expenditure only) would result in different reference tariffs.

The Commission indicated that the principles to be included in the guideline would be consistent with the assumptions adopted in determining the distributors' reference tariffs as part of this review.

Responses to Draft Decision

Envestra repeated the concern it expressed about the Commission's conclusions on charges for Tariff D connections that the use of instruments outside of the Gas Code promotes confusion regarding the interaction between the Gas Code and licence requirements. It also noted that the correct place for any such guidelines is in the Access Arrangements.[97] Multinet commented that it 'does not support nor accept the regulatory basis for the Regulator's proposal to issue a guideline on the parameters for the application of the [economic feasibility test]'. It noted that flexibility in setting the parameters is required to account for such variables as uptake rates, and that the service provider has the responsibility for setting these parameters.[98]

97 Envestra, Response to the Draft Decision, p.25.
98 Multinet, Response to the Draft Decision, p.35.

In contrast, Origin Energy, supported the Commission's proposal to issue guidelines over the administration of the economic feasibility test, for these guidelines to be consistent across the businesses, and for administrative simplifications to be adopted in relation to small customers. It also reiterated its earlier comment that the current *20/20 Rule* is administratively simple.[99]

Further analysis

The Commission confirms the view it expressed in the Draft Decision that the 'economic feasibility test' should form the basis for calculating connection charges for Tariff V customers and surcharges for use of the shared system for Tariff D customers, as proposed by the distributors. The Commission also remains of the view that further guidance on the application of this test is appropriate and that, in the absence of principles in the distributors' proposed Revisions on this matter, a guideline setting out how the Commission would exercise its discretion under the relevant provision in the Distribution System Code is an appropriate response.[100] A consequence of this decision is that the Commission accepts the distributors' proposed Revisions dealing with extension and expansion pricing in clause 5.6.2.

The Commission does not accept Envestra's view that the use of the Gas Distribution System Code will lead to confusion over the role of the respective legal instruments, but rather, considers this instrument to be part of an integrated and consistent regulatory framework. It is noted that the Commission has been careful to align its review of the Gas Distribution System Code with the review of the distributors' proposed Revisions to ensure that the instruments are consistent. Regarding Multinet's concern over the 'regulatory basis' for the administration of the test, the Commission notes that it has discussed the regulatory issues concerned with infill extensions in an earlier consultation paper.[101] It concluded then that the distributors are likely to retain substantial market power with respect to infill projects, and has not been convinced that it should change its view.

Only Multinet and Origin Energy commented on the broad principles proposed by the Commission in the Draft Decision to be used when applying the economic feasibility test. In particular, Multinet argued for greater flexibility, while Origin Energy argued for greater administrative simplicity. For the purposes of this Final Decision, the Commission has assumed that the economic feasibility test would be applied in a manner similar to that set out in the Draft Decision, as summarised above.

---

99 Origin Energy, Response to Draft Decision, 24 July 2002, p.1.

100 The new clause (once it enters into effect) will be clause 3.1(c) of the Draft Gas Distribution System Code, Version 8.0. This replaces a similar clause in the current version of the Gas Distribution System Code.

101 Op. cit., Position Paper, p.24.

The Commission intends to consult on the development of its guidelines on the application of the economic feasibility test, which will provide the opportunity to further consider Multinet and Origin Energy's views, and those of others. However, in assessing reference tariffs the important assumption is that the capital and operating cost used in the feasibility test would include incremental expenditure only. The Commission intends to reflect this assumption in the guideline. Had a different assumption about this principle been adopted, then it is likely to have resulted in different reference tariffs.

Final Decision

The Commission accepts the distributors' proposed Revisions in relation to the pricing of extensions and expansions (clause 5.6.2).

The Commission will address its concerns about the degrees of freedom in the application of the economic feasibility test by issuing a guideline that explains how it would exercise its power to set charges for the connection of customers (within a defined area) under the Gas Distribution System Code.[102] The Commission will consult on this guideline, subject to the comments about the assumptions important for reference tariffs noted above.

2.7.4 Extensions to unreticulated towns

Background and distributors' proposals

In consultation undertaken prior to this review, the Commission noted that it considered that a key issue for the review is to settle upon how projects to extend gas networks to currently unreticulated towns would be treated for regulatory purposes. Much of the discussion in these papers drew upon the Commission's consideration of the regulatory issues associated with these projects in the context of an earlier decision.[103] In particular, it discussed a number of objectives it considered relevant for assessing the form of regulation for these projects, chief amongst which was that customers receive gas distribution services where it is efficient to do so.[104] The Commission also noted that, irrespective of the regulatory approach adopted, it is important that all parties should have clear expectations as to the implications of regulatory arrangements for projects of this type that are undertaken over the next regulatory period.[105]

The distributors' access arrangement submissions acknowledged that the design of regulatory arrangements for projects to extend gas to unreticulated townships raises a number of complex issues. Multinet noted that:

---

102 As noted above, the clause exists currently (clause 3.3 of the Gas Distribution System Code, Version 7.0), and the Commission has proposed retaining this power (with modifications) into the next regulatory period (clause 3.1 of the Draft Gas Distribution System Code, Version 8.0).

103 Office of the Regulator-General, Application for Revision to Westar's (TXU) Gas Access Arrangement, Final Decision, February 2001.

104 Office of the Regulator-General, Position Paper, p.19, Further Guidance to Gas Distributors, p.28.

105 Op. cit., Further Guidance to Gas Distributors, p.28.

> there are no 'quick fixes' to this issue, and the company is keen to work with the Government and the Regulator to develop a sound and economically feasible way forward that meets the legitimate needs of all stakeholders.[106]

The three distributors have each proposed policies related to extensions to unreticulated townships that are essentially identical.[107] Whilst they proposed retaining the flexibility for individual projects to be kept outside of the existing Access Arrangement, the proposed Revisions set out how the regulatory arrangements would apply to the projects that are covered by the existing Access Arrangement.[108] Broadly, the policy set out in the distributors' proposed Revisions for these projects is:

- the distributors would undertake an initial feasibility assessment of the project (that is, look at the cost of serving the township, compared to the price of competitive fuels).[109]
- The distributors would seek the Commission's agreement with respect to the regulatory arrangements for the project. Where it proceeds and will be covered by the existing Access Arrangement, the regulatory treatment will be:
    - The net financing cost[110] incurred by the distributors as a result of undertaking a project within the regulatory period will be carried forward and added to the regulatory asset base (and hence permitted to flow through into reference tariffs) from the commencement of the next regulatory period;[111]
    - The expenditure on the project that is not recovered through a separate charge (a surcharge) will be included in the distributors' regulatory asset bases from the commencement of the next regulatory period; and
    - The cost associated with the project will be quarantined from the operation of the efficiency carryover mechanism, discussed in section 3.8.
- The distributors would retain discretion as to whether a project should proceed (amongst other things, not binding the distributor to undertake the project if it cannot raise competitively priced finance).

106 Multinet, Access Arrangement Information, p.9.

107 The only practical difference across the distributors is that Envestra has not included a commitment to undertake an initial feasibility assessment. This matter is discussed below.

108 The Commission expects the majority of such projects to be covered by the existing Access Arrangements as this allows individual projects to be pooled, and hence reduce the earnings uncertainty associated with each project considered on a stand-alone basis.

109 As noted in footnote 107, Envestra's proposal excludes a commitment to undertake an initial feasibility assessment.

110 Multinet and TXU refer to the 'net financing cost' incurred within the period, whereas Envestra refers to 'any cost (which includes the time value of money) not recovered' during the regulatory period. The Commission considers these clauses to refer to precisely the same concept.

111 Each of the distributors' policies in relation to these projects only apply in respect of projects that were not taken into account in the assessment of reference tariffs. Accordingly, this net financing cost would not have been reflected in reference tariffs.

The Commission notes that the proposed regulatory treatment of these projects corresponds to the 'Interim Policy for Extensions to Currently Unreticulated Townships' described in the Commission's previous decision on a Revision proposed by TXU in relation to such a project,[112] as noted in TXU's submission.[113]

Draft Decision

In the Draft Decision, the Commission concluded that the distributors' proposed policies for projects to extend natural gas networks to unreticulated towns provide an appropriate means of addressing these projects if they arise within a regulatory period. Accordingly, it proposed to adopt the distributors' proposals, without revision.

It noted that a key element of the proposed policies was that the adopted the Interim Policy adopted in the current regulatory period. The Commission considered that it was appropriate to continue this policy and noted the distributors' positive comments about their commitment to connecting new customers and extending the distribution system to unreticulated areas, including TXU's comments that:

> TXU Networks remains committed to extending its Distribution System and providing gas infrastructure to regional towns where such investment provides an appropriate balance of outcomes for each of the stakeholders.[114]

As one of the Commission's key concerns was to ensure that all parties have clear expectations as to the implications of regulatory arrangements for projects of this type, the Draft Decision also set out its views about how it expected these arrangements to operate in practice.

Responses to Draft Decision

In response to the Draft Decision, Multinet noted the Commission's acceptance of its proposed policy without further comment, while Envestra did not comment on the matter. TXU welcomed the Commission's consideration of the issues discussed in the Draft Decision, and noted that it intends to develop a strategy for extending gas to various regional centres. TXU also noted its preference for including such projects under a separate Access Arrangement.

---

112 Office of the Regulator-General, Application for Revision to Westar's (TXU) Gas Access Arrangement, Final Decision [Westar Final Decision], February 2001, pp.21-22.

113 TXU, Access Arrangement Information, p.6.

114 TXU, Access Arrangement Information, p.6

While not discussed in the Draft Decision, the Commission received a submission from Moira Shire describing its efforts to facilitate the extension of the gas network to Nathalia.[115] Subsequent to the Draft Decision, the Commission received a number of papers from Infrastructure Access Services that recorded its efforts to facilitate the supply of gas to regional areas. One paper included recommendations about alternative means of financing projects that are considered marginal to investors (such as through 'local bonds'), and for the regulatory arrangements to provide greater certainty and predictability to investors.[116] However, no specific comments were made on the proposals set out in the Draft Decision.

Further analysis

The Commission remains of the view that the distributors' proposals with respect to projects to extend supply to unreticulated towns are appropriate, and proposes to accept them without revision. However, it remains concerned that all parties have clear expectations as to the implications of regulatory arrangements for projects of this type. Accordingly, the views it expressed in the Draft Decision as to how it considered these arrangements would operate in practice are repeated below.

Regarding the comments made by Moira Shire, the Commission reiterates its support for the extension of the gas network to unreticulated towns where it is economic to do so, and considers that the proposals set out in this Final Decision will facilitate this outcome. While not expressing a view about the extension of gas to Nathalia, the Commission notes that the regulatory framework to which the Commission is subject provides it with limited scope to facilitate the extension of gas where it is not efficient to do so. Moreover, even where one party's analysis suggests that a project would be economic, the decision of whether or not to proceed is ultimately a matter for the relevant distributors' commercial judgment.

In relation to Infrastructure Access Services' comments, the Commission considers that the distributors' proposed arrangements for the regulatory treatment of these projects – and the Commission's acceptance of these proposals without revision – should reduce the perceived barriers to these projects stemming from the regulatory arrangements. The Commission also notes that these regulatory arrangements would also facilitate novel financing arrangements for these projects, such as those discussed at the Creswick Forum.

As noted above, TXU has expressed a preference for including such projects in a separate Access Arrangement. In the Draft Decision, the Commission noted its view that including new projects into its existing Arrangement would be expected to reduce the risk associated with these projects while not creating cross-subsidies. It also noted that these projects could be quarantined effectively from the operation of the efficiency carry-over, and be provided with the regulatory certainty sought even included in the same Access Arrangement. That said, the Commission will discuss this issue in good faith with TXU in the context of specific proposals and ensure that regulatory impediments to such projects are minimised.

---

115 Moira Shire, Submission to 2003 Gas Distribution Price Review, 14 March 2002.

116 Infrastructure Access Services, The Creswick Forum on Gas Access for Rural and Regional Victoria, 5 July 2002, p.2.

Practical application unreticulated towns policy

COVERAGE OF THE NEW PROJECTS – EFFECT OF 'ROLLING-IN' EXPENDITURE

The distributors have noted that where new projects are to be covered by the existing Access Arrangements, the 'recoverable portion' of the capital expenditure associated with the project will be included in the distributors' regulatory asset bases from the start of the next regulatory period. The 'recoverable portion' refers to the amount of expenditure that is economically feasible at the tariff that would apply to the new project. The distributors would be permitted to recover the remainder of the cost associated with undertaking the project directly from those benefiting from the project through an additional charge referred to as a surcharge (discussed separately below).

Including the 'recoverable portion' associated with a project in the distributors' regulatory asset bases substantially diminishes the level of uncertainty associated with the recovery of this expenditure over the long term. In this Final Decision, the Commission has reiterated its view that there are substantial benefits to both customers and distributors from a policy of minimising the risk to distributors associated with recovering the regulatory value of their assets. Consistent with this, it has noted that it would provide the distributors with a degree of flexibility over how fast capital is returned to them, and also made a commitment not to seek to identify and remove redundant assets at future price reviews (see section 3.6).

As a result, the practical implication of including the expenditure in the regulatory asset base is that the distributor's ability to recover this expenditure is dependent only upon the viability of its whole distribution network, not the viability of the new project in isolation. The Commission would expect that some new projects might turn out to be more profitable than expected, whereas others may turn out to be less profitable than expected. Hence, on average, rolling-in these projects would not be expected to affect the prices charged to existing customers. However, reducing the distributors' earnings uncertainty by being able to 'pool' all of their projects should improve the prospects of extending gas networks to new areas.

The Commission also notes that the 'pooling' of assets – and consequent reduction in uncertainty over recovery of investments over the long term – is only available where the new projects are included under the existing Access Arrangements. Accordingly, while the distributors' proposed Revisions will preserve the flexibility for projects to be kept outside of the existing Access Arrangements, the Commission would expect the distributors to seek to include these projects under the existing Access Arrangement to make use of the reduction in earnings uncertainty associated with rolling-in the expenditure.

RECOVERY OF COSTS INCURRED WITHIN THE REGULATORY PERIOD

The Commission has accepted previously that where these projects are undertaken during a regulatory period, the distributors may suffer a net financing loss during the regulatory period (unless this matter is otherwise addressed).

First, even though the distributors would be permitted to levy a surcharge to ensure that a project is economically feasible (that is, more revenue than cost is expected over the life of the project, in present value terms), the profile of revenue and expenditure may lead to a net financing loss during the regulatory period. This arises because typically, much of the cost associated with the project is incurred at the start, and customers only connect (and so revenue is only received) over time – with the timing difference implying a financing loss over the period.

As an example, if a project costs $1 million, then the cost of financing the investment would be approximately $70 000 per annum (assuming a cost of capital of 7 per cent). If revenue (net of operating costs) were $10 000 in the first year, and $20 000 in the second, then a net financing loss of $60 000 and $50 000 in these years would result.

The distributors have proposed addressing this concern by quantifying the financing loss incurred within the regulatory period and adding it to the regulatory asset base from the start of the next regulatory period – as the Commission proposed in its Interim Policy. However, after the subsequent price review, failing to align the revenue and cost for a specific project would no longer create a financing loss because the expenditure and revenue associated with the project would be taken into account when setting reference tariffs across the whole system – and so customers would bear (or benefit from) the annual net financing cost (or benefit) associated with the project.

The second means through which the distributors could suffer a financing loss within the regulatory period is through the operation of the efficiency carryover arrangements (discussed in section 3.8). Under the CPI-X price path approach and efficiency carryover arrangements adopted by the Commission, the distributors retain the benefit associated with out-performing against the cost benchmarks reflected in the price controls. This implies that undertaking a new project – which would require additional expenditure – would reduce the efficiency-benefit that would otherwise be received (ie. an opportunity cost).

The Commission has noted elsewhere that it is undesirable to penalise the distributors for undertaking additional expenditure where this is required to produce additional output, and proposed a mechanism to adjust the carryover to take account of the level of output delivered. However, with respect to projects to extend gas networks to new towns, the simplest means of ensuring that the efficiency carryover mechanism does not penalise the distributors for extending their networks is to quarantine this expenditure from this mechanism – which the distributors have proposed.

ECONOMIC FEASIBILITY AND RECOVERY OF SURCHARGES

While the act of including the ‘recoverable portion’ of the expenditure associated with a project in a distributor’s regulatory asset base will substantially reduce the uncertainty associated with future earnings associated with this expenditure, the distributors may bear earnings uncertainty during the early years of a project. This reflects the fact that revenue from these projects depends upon the rate at which customers choose to connect to natural gas, as well as the amount of gas consumed (which will depend upon the rate at which existing appliances are replaced with natural gas appliances). In addition, as the recovery of the remaining expenditure – the surcharge – would depend upon the long-term profitability of each project, the distributors may also face some uncertainty as to the recovery of this amount.

Regarding the first source of uncertainty, the Commission would expect that this would be reflected in the forecasts of revenue and costs that are used to assess the economic feasibility of the projects (and size of surcharges – discussed below), and when reference tariffs are re-set at future price reviews. That is, it would not expect these forecasts to reflect the distributors' most optimistic scenario for the project, but rather that the forecasts take account of all potential scenarios, including that connection and conversion rates may be lower than the central case.

Regarding surcharges (discussed above), a surcharge is an additional contribution made by customers (upon connection), or by another third party (typically as an upfront payment) effectively to 'bridge the gap' between the costs of connecting a town to the network and the revenue expected from those customers under reference tariffs. Recovery of the surcharge amount will also depend on uncertain connection and conversion rates, and ultimately, on the profitability of the particular project.

The Commission notes that there are a number of possible options available to the distributors to reduce the uncertainty associated with the recovery of surcharge amounts, which the Commission would support.

If large industrial customers are to be served by the project, the Commission would expect the distributor to require those customers to enter into a contract in respect of future charges (including surcharges) prior to committing to the project. While individual contracts may not be feasible in respect of residential customers, one option would be for the local council to pay the surcharge amount, and then recover that amount from the beneficiaries of the project (ie. though council rates).

The size of the surcharge required from a project would depend upon forecasts of future connection and conversion rates. Accordingly, large customers and councils may wish to enter into agreements whereby they bear some of the risk associated with these rates. Such an approach would be attractive to a large customer or council where it considered the forecasts adopted by the distributor to be overly conservative. At one end of the spectrum, industrial customers and the council could agree to meet the entire upfront cost of reticulating a town, and then be reimbursed by the distributor on the basis of actual take-up rates. A myriad of other risk-sharing options also exist.

The Commission considers that arrangements for the recovery of surcharge amounts – and any associated risk-sharing arrangements – like those discussed above, could be accommodated within the distributors' proposed Revisions (and the Gas Code). The Commission would support any arrangements for the recovery of surcharge amounts that may be negotiated between the distributors and large customers or local councils (or other parties acting on behalf of customers).

DISTRIBUTORS' DISCRETION TO PROCEED

A final issue related to the distributors' proposed Revisions for unreticulated towns involves the sole discretion that distributors ultimately have as to whether such projects proceed. Clause 5.6.3 of each distributor's proposed Revisions notes that even after agreement has been reached with the regulator over the regulatory treatment of the project, and a detailed feasibility analysis has been undertaken, the distributor may veto a project on any ground.

The Commission accepts that reserving an absolute discretion as to whether to proceed with such projects in the distributors' proposed Revisions merely reflects a statement of their legal rights under the Gas Code.[117] However, it also considers that it is not in the interests of any party for community expectations to be built up about the prospect of receiving gas, and to then have a project vetoed by the distributor. To this end, the Commission would expect distributors to undertake thorough economic evaluations of prospective extensions to unreticulated towns, as set out in their proposed Revisions, before approaching the Commission to discuss the regulatory treatment of such projects. It would also expect the distributors to consult with affected communities in developing such proposals. Lastly, the Commission would expect the distributors to exercise their discretion to veto a project in a responsible and transparent manner, which should include full disclosure of the reasons for not proceeding with such a project, particularly if this occurs after community expectations have been built up.

Final Decision

The Commission accepts without revision each of the distributors' proposed policies with respect to the treatment of projects to extend gas distribution networks to unreticulated towns.

2.7.5 Projects meeting the 'Safety, Integrity or Contracted Capacity Test'[118]

Background and distributors' proposals

Under the Gas Code, distributors are permitted to include capital expenditure required to maintain the 'safety, integrity or contracted capacity of services' in their regulatory asset base when this is updated at a price review.[119]

Each of the distributors proposed a clause in their proposed Revisions that refers to this test.[120] This clause provides that if the distributor considers during the regulatory period that some of its capital expenditure meets this requirement, they may propose Revisions that have the effect of raising reference tariffs immediately (and thus permitting that capital expenditure to be 'rolled-in' to the capital base immediately). In further correspondence between distributors and the Commission prior to the Draft Decision, TXU and Envestra indicated that the Revision is either not material[121] or 'merely restates the right of a Service Provider to lodge a Revision to the Access Arrangement at any time…'.[122]

117 Sections 3.16 and 6.22 of the Gas Code.
118 The Commission erroneously used the term 'system-wide benefits test' in the Draft Decision rather than the 'safety, integrity or contracted capacity test'. The former is a reference to the test set out in section 8.16(b)(ii) of the Gas Code, which was not the relevant provision. However, the correct provision was identified and discussed in the text.
119 Section 8.16(b)(iii) of the Gas Code.
120 Section 5.6.2 (e) of the Gas Code.
121 Letter from P. Murphy (TXU) to N. Southern (ESC), 9 May 2002.
122 Letter from A. Staniford (Envestra) to N. Rizos (ESC), 9 May 2002.

Draft Decision

In the Draft Decision, the Commission required the distributors to remove the proposed reference to the 'safety, integrity or contracted capacity test' from their proposed Revisions.

The Commission noted that if a distributor considers that a Revision to reference tariffs within the regulatory period is justified, then under the provisions of the Gas Code it is free to propose such Revisions accordingly and have them considered by the Commission pursuant to the process and principles set out in the Gas Code. As a result, the clause appears unnecessary.

The Commission also noted that the distributors' proposal to include such a clause reflected a misunderstanding of the workings of CPI-X regimes. In particular, it noted that a re-opening of the price caps as contemplated by the clause would imply a substantial weakening of the incentives for the distributors to be efficient. It noted that the issue is not immaterial, as a *substantial portion* of the distributors' proposed capital expenditure for the next regulatory period would meet the requirement of being necessary to maintain the 'safety, integrity or contracted capacity of services'.

The Commission noted that it had assessed a proposal by one of the distributors to re-open price caps within the current regulatory period, and rejected the proposal largely for the reasons noted above. Thus, it noted that while the distributors have the freedom to make proposals during the regulatory period of the form implied by clause 5.6.2 (e), the Commission noted that the inclusion of this clause in the Access Arrangements may provide a misleading impression of the incentive properties included elsewhere in the Access Arrangements, as well as the likely response to such a proposal. The Commission considers that both of these outcomes are inconsistent with the interests of users and prospective users and the public interest.

Responses to Draft Decision

TXU and Envestra opposed the Commission's proposed rejection of clause 5.6.2(e) of distributors' proposed Revisions. Both TXU and Envestra argued that clause 5.6.2(e) reflects the current position of the Access Arrangements.[123] TXU also noted that this clause merely 'reflects its rights and the intent of the Access Code in this matter',[124] and Envestra argued that the clause complies with section 3.16 of the Gas Code, and that a similar provision has been accepted by other jurisdictional regulators.[125]

123 TXU, Response to the Draft Decision, p.39; Envestra, Response to the Draft Decision, p.9.
124 TXU, Response to Draft Decision, 8 August 2002, p.39.
125 Envestra response to Draft Decision, 9 August 2002, p.9.

Further analysis

As outlined above, the distributors indicated that there was an error in the Draft Decision in the Commission's proposed amendment on this clause. Specifically, in the Draft Decision the Commission proposed to that each of the distributors should delete the whole of clause 5.6.2(e). However, that clause included two provisions, the first of which referred to projects that would pass the 'system-wide benefits test' in the Gas Code (section 8.16(b)(ii)), and the second that referred to projects that would meet the 'safety, integrity or contracted capacity test' (section 8.16(b)(iii)). The Commission's concerns pertained to the latter provision, and it was the intention only to require that latter provision be removed (ie. clause 5.6.2(e)(ii)).

With respect to Envestra and TXU's comments on the position of the distributors' existing Access Arrangements, the Commission notes that clause 5.6.2(e) does not replicate the current clause in the distributors' Access Arrangements. The current clause only refers to the 'system-wide benefits test'. Consistent with the discussion above, the Commission would not object to the continuation of the current provision.

However, the Commission remains of the view that modifying the current clause to refer to the 'safety, integrity or contracted capacity test' is inappropriate. In assessing the distributors' reference tariffs, the Commission has assumed that the distributors would continue to deliver current levels of service over the next regulatory period, and undertake all necessary expenditure to achieve this end. Were the Commission to foreshadow a re-opening of the price caps within the period to recognise a higher cost of meeting these expected service levels, then there would be a substantial weakening of the incentives for the distributors to meet these service levels at minimum cost.

Thus, while the distributors are free to make proposals during the regulatory period of the type implied by clause 5.6.2(e)(ii), the Commission remains of the view that the presence of this clause in the distributors' Access Arrangements may provide a misleading impression of the incentive properties included elsewhere in the Access Arrangements. The Commission also considers that it may provide a misleading impression of the likely response to such a proposal. Moreover, to the extent that the clause would provide the distributors with rights that they would not already have under the Gas Code, then the Commission would consider that such additional rights would be inappropriate. While the ability to have price caps re-opened may promote the distributors' legitimate business interests (that is, to maximise shareholder returns), it would not be in the interests of users or prospective users, and the substantial weakening of incentives would be adverse to the efficient operation of the networks, and not be in the public interest. On balance, the Commission considers that the latter considerations should prevail.

As the Commission never intended to reject the first limb of clause 5.6.2(e) of the distributors' proposed Revisions, the Commission considers it appropriate to permit this provision to remain. The simplest means of achieving this end is to require that the equivalent clause in the distributors' current Access Arrangements (clause 5.7.2(e)) continue to apply.

Final Decision

The Commission considers that the reference to the ‘safety, integrity or contracted capacity test’ in clause 5.6.2(e) should be deleted, which would be achieved by continuing the operation of the equivalent clause in the distributors’ current Access Arrangements (clause 5.7.2(e)).

AMENDMENT REQUIRED
Each of the distributors is required to replace clause 5.6.2(e) of their proposed Revisions with clause 5.7.2(e) from their current Access Arrangements.

3 ASSESSING TOTAL REVENUE

3.1 Approach to calculating total revenue

In its Draft Decision, the Commission provided an overview of the approach used to assess the total revenue proposed by the distributors, which included a description of the key provisions of the Code relating to reference tariffs. In response to the Draft Decision, a number of submissions commented on the Commission's overall approach. This section outlines the Commission's consideration of these comments and clarifies the approach adopted by the Commission in this Final Decision in light of the requirements of the Gas Code.

3.1.1 Form of regulation, principles and objectives

The form of regulation proposed by the distributors and adopted by the Commission is referred to in the Gas Code as the 'price path' approach.[126] This approach involves determining a path for reference tariffs that is forecast to deliver a revenue stream calculated consistently with the principles in the Gas Code and section 9 of the Tariff Order. Once the CPI-X price caps are set using this approach, no adjustments are made to take into account subsequent events until the commencement of the next regulatory period.[127]

There are two distinct steps involved in determining the new price caps to apply to the reference tariffs:

- deriving a benchmark total revenue requirement in respect of the regulated services that is consistent with the principles set out in the Gas Code; and
- designing a set of price controls such that the revenue expected to be earned by applying those controls equates with the benchmark total revenue requirement, taking into account the expected sales of the reference service.

The Gas Code allows for the benchmark total revenue to be calculated so as to equal the expected cost of providing the regulated services using the methodology commonly referred to as the 'building block' approach.[128] Broadly, the total revenue benchmarks are determined by the following:

- the regulatory asset base to apply to each distributor's business from 1 January 2003;

---

126 Section 8.3(a) of the Gas Code. This form of regulation is also referred to as CPI-X or price cap regulation.

127 This contrasts with the 'cost of service' approach described in the Gas Code, which envisages adjustments being made to reference tariffs in light of actual outcomes to ensure that distributors recover the costs of service provision.

128 Section 8.4 of the Gas Code provides a choice of three methodologies for determining total revenue benchmarks, which includes the cost of service or building block approach. 'Cost of service' is also a term used to refer to the form of regulation under section 8.3 of the Code, and so the term 'building block approach' is used to avoid confusion.

- a rate of return on each distributors' regulatory asset base from 1 January 2003 (including any forecast capital expenditure) and a return of capital (depreciation) over the regulatory period;
- a forecast of the operating, maintenance and other non-capital costs over the period; and
- as an incentive mechanism, an allowance for any efficiency gains that have been made by the distributors in the current regulatory period.

The Gas Code sets out a number of general principles against which the Commission is required to assess the reference tariffs in the distributors' proposed Access Arrangement Revisions. These include the general objectives specified in section 8.1 of the Gas Code, namely:

> A Reference Tariff and Reference Tariff Policy should be designed with a view to achieving the following objectives:
>
> (a) providing the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the Reference Service over the expected life of the assets used in delivering that Service;
>
> (b) replicating the outcome of a competitive market;
>
> (c) ensuring the safe and reliable operation of the Pipeline;
>
> (d) not distorting investment decisions in Pipeline transportation systems or in upstream and downstream industries;
>
> (e) efficiency in the level and structure of the Reference Tariff; and
>
> (f) providing an incentive to the Service Provider to reduce costs and to develop the market for Reference and other Services.[129]

Section 8.1 further specifies that:

> To the extent that any of these objectives conflict in their application to a particular Reference Tariff determination, the Relevant Regulator may determine the manner in which they can best be reconciled or which of them should prevail.[130]

In addition, section 8.2 of the Gas Code outlines the factors about which the Commission must be satisfied in determining to approve a reference tariff and reference tariff policy, which are:

> (a) the revenue to be generated from the sales (or forecast sales) of all services over the access arrangement period (the Total Revenue) should be established consistently with the principles and according to one of the methods contained in this section 8;
>
> (b) to the extent that the Covered Pipeline is used to provide a number of Services, that portion of Total Revenue that a Reference Tariff is designed to

[129] Section 8.1 of the Gas Code.
[130] ibid.

recover (which may be based upon forecasts) is calculated consistent with the principles contained in this section 8;

(c) a Reference Tariff (which may be based upon forecasts) is designed so that the portion of Total Revenue to be recovered from a reference service (referred to in paragraph (b)) is recovered from the Users of that Reference Service consistently with the principles contained in this section 8;

(d) Incentive Mechanisms are incorporated into the Reference Tariff Policy wherever the Relevant Regulator considers appropriate and such Incentive Mechanisms are consistent with the principles contained in this section 8; and

(e) any forecasts required in setting the Reference Tariff represent best estimates arrived at on a reasonable basis.[131]

In assessing whether a reference tariff meets these and other requirements of section 8, section 8.49 provides that:

> Subject to the requirements of public consultation, the Relevant Regulator may determine its own policies for assessing whether a Reference Tariff meets the requirements of section 8.[132]

In applying this section of the Gas Code, the Commission may, for example:

> Draw an inference that an appropriate Incentive Mechanism..[or]...policy by the Service Provider will result in New Facilities Investment…and/or…Non-capital Costs that meet the requirements of section[s]…[8.16 and]…8.37 [respectively].[133]

Sections 8.16 and 8.37 require that both capital costs and non-capital costs provided for in reference tariffs do not exceed those that would be incurred or invested by:

> …a prudent Service Provider acting efficiently, in accordance with accepted good industry practice, and to achieve the lowest sustainable cost of delivering Services [or the Reference Services].[134]

In addition to the specific requirements of section 8 in relation to reference tariffs, section 2.24 specifies a range of matters that the Commission must take into account when assessing a proposed Access Arrangement, namely:

(a) the Service Provider’s legitimate business interests and investment in the Covered Pipeline;

(b) firm and binding contractual obligations of the Service Provider or other persons (or both) using the Covered Pipeline;

(c) the operational and technical requirements necessary for the safe and reliable operation of the Coverer Pipeline;

(d) the economically efficient operation of the Covered Pipeline;

---

131 Section 8.2 of the Gas Code.
132 Section 8.49 of the Gas Code.
133 ibid.
134 Section 8.16 and 8.37 of the Gas Code

(e) the public interest, including the public interest in having competition in markets (whether or not in Australia);

(f) the interests of Users and Prospective Users;

(g) any other matters that the Relevant Regulator considers are relevant.[135]

3.1.2 Responses to Draft Decision

The Commission invited comments on its Draft Decision by 5 August 2002, and substantive submissions were made by each of the three distributors, the Energy Users Coalition of Victoria, and a number of other parties. The main theme arising in the distributors' submissions related to the overall principles and objectives applied in the Draft Decision was that the Commission had not, in fact, adopted an overall approach in line with that suggested by the Productivity Commission's (then) Position Paper on the review of the national access regime.[136] For example, Multinet said:

> The Draft Decision is represented by the Regulator as being 'conservative', however, the above points indicate that there is ample evidence within the Draft Decision to suggest that the Regulator remains focused on delivering short-term price gains for consumers, in spite of the Productivity Commission's warnings about regulators attempting to be too ambitious regarding the precision of their decisions in the presence of uncertainty.[137]

Envestra submitted that:

> When we dig beneath the Draft Decision, we see little evidence to suggest that the Commission has adopted the PC advice to err on the side of investors. While the Commission on page 135 claims that it had adopted a number of conservative assumptions that systematically favour investors, in reality is has erred significantly on the side of existing consumers, and is done so has further jeopardized long-term investment in gas distribution infrastructure in Victoria.[138]

On the other hand, TXU commented that:

> TXU Networks is pleased to note that in terms of high-level principles for regulation, the Commission generally concurs with the sentiments expressed by the Productivity Commission.[139]

In contrast, the Energy Users Coalition commented that:

> In adopting assumptions that 'systematically favour the distributors', the Commission has failed to provide rights for access on conditions that are fair and reasonable to <u>both</u> service providers and users.[140]

---

135 Section 2.24 of the Gas Code.
136 Productivity Commission, *Review of the National Access Regime*, Position Paper, March 2001.
137 Multinet, Response to Draft Decision, p.5.
138 Letter from O G Clark (Managing Director, Envestra), to J Tamblyn (ESC), 9 August 2002
139 TXU, Response to Draft Decision, p.16.
140 Energy Users Coalition of Victoria, Response to Draft Decision, 29 August 2002, p.2.

Subsequent to the Commission's due date for submissions in response to the Draft Decision, on 23 August 2002 the Full Court of the Supreme Court of Western Australia handed down its judgment in the matter of: Re Dr Ken Michael AM; ex parte Epic Energy (WA) Nominees Pty Ltd & Anor [2002] (the 'Epic judgment').

Shortly thereafter, the Assistant Treasurer released the final report of the Productivity Commission's review of the national access regime[141], and announced its decision, *inter alia*, to incorporate an objects clause in Part IIIA of the Trade Practices Act 1974 that clarifies that the object of that part is to:

> (a) promote the economically efficient operation and use of, and investment in, essential infrastructure services, thereby promoting effective competition in upstream and downstream markets; and
>
> (b) provide a framework and guiding principles to encourage a consistent approach to access regulation in each industry.[142]

Whilst both these developments represent important milestones in the evolution of the principles and practice of economic regulation of access to essential infrastructure, the guidance provided by the WA Supreme Court's decision in the Epic case is fundamental since it is directed at the specific provisions of the Code that the Commission is bound to apply.

In a further submission following the Epic judgment, Envestra pointed out that:

> The *Epic Energy Appeal* clarified interpretation of the Code, by providing order to 'guide' regulators in exercising their power when approving Access Arrangements.[143]

In interpreting and applying the Epic judgment, Envestra urged that the Commission:

> Not strive to replicate the theoretical 'perfectly' competitive market;
>
> Deliver outcomes consistent with a 'workable' competitive market. This involves tolerance of a degree of market power;
>
> Have regard to the broader aspects of political intent and public interest, beyond the objective of the promotion of a competitive market;
>
> Give fundamental weight to the factors in section 2.24 in the assessment of Access Arrangements (eg. legitimate business interests of the service provider); and
>
> Give regard to the particular circumstances of each individual pipeline, rather than adopt a 'one size fits all' approach derived from a strict application of economic theory.[144]

The Australian Gas Association also submitted a high level analysis of the Draft Decision refering to the Epic judgment, and contended that elements of the Draft Decision amounted to errors of law, such as:

---

141 Productivity Commission, *Review of the National Access Regime*, Report No. 17, 2001.
142 Ibid, Recommendation 6.1.
143 Envestra, Albury & Victorian Access Arrangement, Summary Submission, 12 September 2002, p.3.
144 ibid, p.4.

incorrectly interpreting section 8.1(a) as an 'overarching requirement';

incorrectly characterising the requirement of section 2.24 when assessing the proposed Access Arrangements;

failing to take into account section 2.24 factors in reconciling the principles in section 8.1;

incorrectly interpreting into section 8.1(a) that revenue should be 'just sufficient to ensure continued service provision'; and

giving undue weight to one factor in section 8.1(a).[145]

3.1.3 Clarifying the approach used in the Final Decision

In making its Final Decision on each of the distributors' proposed Revisions, the Commission's foremost consideration is its consistency with the requirements of the Gas Code. In interpreting the Gas Code and the Tariff Order requirements, the Epic judgment represents the most authoritative assessment available, and the Commission has considered its implications carefully in making this Final Decision.

In addressing the juxtaposition of section 8 and section 2.24 of the Gas Code, an important finding of the Court in the Epic judgment was that where assessing reference tariffs against the requirements of section 8.1 identified tensions, a regulator must give fundamental weight to the objectives specified in section 2.24.

However, the objectives set out at section 2.24 themselves involve tensions. As noted by the Court:

> At every one of these points [sections 2.24, 8.1, 8.10 and 8.11], however, there is also the tension of potentially conflicting considerations or objectives. The nature of that potential for conflict remains generally consistent, although given more particular and precise expression in the different context of those provisions.[146]

The Commission notes that, while clarifying the legal interpretation of the Gas Code, the Epic judgment emphasised that it is the regulator's responsibility to consider and weigh the various objectives of the Gas Code:

> It must be remembered, however, that once the basic issues of interpretation are clarified it is for the Regulator, not this Court, to consider and weigh those factors and objectives. It is for the Regulator to assess the relevance and weight of each of these factors and objectives and to exercise the discretions that are committed by the Code to him.[147]

145 Australian Gas Association, Review of the Victorian Gas Access Arrangements, Implications for the Draft Decision form the Epic Energy Supreme Court Judgment, 6 September 2002.
146 Epic Judgment, para 185.
147 Ibid, para 187.

In the course of exercising the discretions due to it under the Gas Code, the Commission has adopted assumptions for some components of its total revenue assessment that differ from those submitted by the distributors. In adopting such alternative assumptions, the Commission has been mindful of the specific requirement of section 8.2(e) that:

> any forecasts required in setting the Reference Tariff be best estimates arrived at on a reasonable basis.

The Commission commenced a public consultation process in May 2001 that sought to develop its approach to assessing the underlying cost benchmarks and the CPI-X incentive mechanism to be applied to reference tariffs. An important theme of the approach to determining expenditure benchmarks involved adopting an inferential approach, whereby:

- capital costs incurred during the period 1998-2002 were taken to be efficient, by virtue of the incentive mechanisms applying over the period, and so were added to the capital base without specific review for their prudence or efficiency;
- expenditure benchmarks for capital and non-capital costs for the 2003-07 regulatory period have been developed based on levels and trends in current expenditure which, again, were taken to be indicative of those which would be incurred by a prudent service provider, acting efficiently, as adjusted for any step changes in functions;
- similarly, demand forecasts have been developed based on trends in gas usage, updated for reasonable expectations in relation to various drivers of future demand; and
- finally, a CPI-X price path has been applied for a fixed, five year period, thereby providing the distributors with continuing incentives to reveal through their actions, the levels and trends in costs from which inferences can similarly be drawn when the total revenue calculation is next reviewed.

The Commission has not conducted a detailed, firm specific assessment of forecast capital and non-capital costs. Rather, it has relied on adopting a less intrusive, inferential approach that draws on the incentive properties of the current and prospective Access Arrangements to encourage distributors to reveal the efficient cost of providing the regulated services.

On that basis, the range of matters over which the Commission might have otherwise needed to exercise discretion in evaluating the distributors' proposed expenditure benchmarks has been reduced. By giving relatively more emphasis to revealed cost information, the Commission believes it has improved its ability to balance the distributors' legitimate business interests in seeking to maximise returns and the legitimate interests of users in having lower tariffs over the long term.

The Commission's approach provides incentives for distributors to achieve efficient costs because they can keep part of their efficiencies relative to the benchmarks within the access arrangement period and through the operation of the inter-period efficiency mechanism.

The Commission considers that this incentive based approach conforms to the requirements of section 2.24, and that its decision on each component also complies with the specific reference tariff principles set out in section 8 of the Gas Code and section 9 of the Tariff Order.

The remainder of this section discusses each of the components of total revenue in the context of the relevant provisions of the Gas Code as summarised above, and presents the Commission's analysis and conclusions underlying the assumptions used for the assessment of reference tariffs for the purpose of this Final Decision.

3.2 Distributors' proposed revenue & Final Decision

3.2.1 Distributors' proposals

The total revenue proposed by each of the distributors for the 2003-07 regulatory period is set out in their respective Access Arrangement Information. As shown in the table below, the Victorian distributors proposed total revenues in their original submissions that ranged from $587 to $689.7 million. As noted in the Draft Decision, these proposals represent a significant increase in the revenue benchmarks assumed by the former Office of the Regulator-General when it assessed the reference tariffs for the current regulatory period, and is substantially higher than current (weather adjusted) revenues.

TABLE 3.1
DISTRIBUTORS' PROPOSED TOTAL REVENUE REQUIREMENT
($ million in July 2001 prices)

Envestra – Albury	2003	2004	2005	2006	2007	Total
Return on assets	1.9	2.0	2.0	2.1	2.1	10.1
Regulatory depreciation	0.8	0.8	0.9	0.9	1.0	4.3
Operating expenditure	1.8	1.8	1.8	1.8	1.8	8.9
Efficiency carryover	-	-	-	-	-	-
Tax wedge	0.3	0.3	0.3	0.4	0.4	1.7
TOTAL REVENUE	**4.7**	**4.8**	**4.9**	**5.1**	**5.2**	**24.9**
Envestra –Victoria						
Return on assets	51.9	52.3	52.8	53.4	54.0	264.4
Regulatory depreciation	22.1	22.4	22.8	22.9	23.5	113.7
Operating expenditure	42.9	42.6	42.7	43.2	43.8	215.2
Efficiency carryover	-	-	-	-	-	-
Tax wedge	6.8	7.4	7.7	8.0	8.5	38.3
TOTAL REVENUE	**123.6**	**124.7**	**125.9**	**127.6**	**129.8**	**631.7**
Multinet						
Return on assets	61.9	64.5	67.3	69.4	71.3	334.4
Regulatory depreciation	17.2	18.0	19.5	20.7	21.7	97.1
Operating expenditure	50.3	46.1	47.4	46.5	46.7	237.0
Efficiency carryover	1.9	1.3	6.8	1.8	-1.1	10.7
Tax wedge	0.6	1.3	1.9	3.0	3.7	10.5
TOTAL REVENUE	**131.9**	**131.2**	**142.9**	**141.4**	**142.3**	**689.7**
TXU						
Return on assets	52.1	54.4	56.7	59.0	61.0	283.2
Regulatory depreciation	16.1	16.1	16.1	16.1	16.1	80.5
Operating expenditure	45.3	41.1	40.2	40.0	39.4	206.0
Efficiency carryover	-	-	-	-	-	-
Tax wedge	3.0	1.9	3.1	4.2	5.1	17.3
KD Constrained factor	3.7					
TOTAL REVENUE	**116.5**	**113.5**	**116.1**	**119.3**	**121.6**	**587.0**

Note: These figures represent the original figures included in the distributors' proposed Access Arrangement Information as submitted in April 2002. The Commission notes that the distributors made a number of adjustments to these figures throughout this consultation process.

In the Draft Decision, the Commission assessed each of the distributors' proposed forecasts with respect to the key components of total revenue required for the next regulatory period against the requirements of the Gas Code. As a result of its analysis, the Commission adopted alternative assumptions in relation to a number of the components of total revenue.

A summary of the revenue benchmarks adopted in this Final Decision is provided below.

3.2.2 Final Decision total revenue and 'X' factors

As noted in section 3.1, the form of regulation proposed by the distributors and adopted by the Commission is referred to in the Gas Code as the 'price path' approach.[148] This approach involves determining a path for reference tariffs that is forecast to deliver a revenue stream calculated consistently with the principles in the Gas Code and section 9 of the Tariff Order. The sections that follow provide the Commission's consideration of the components that flow through to the establishment of this revenue stream. The amounts used for the purpose of this Final Decision are provided in the table below for each year of the next access arrangement period.

148 Section 8.3(a) of the Gas Code. This form of regulation is also referred to as CPI-X or price cap regulation.

TABLE 3.2
REVENUE FINAL DECISION: COMPONENTS OF TOTAL
($ million in July 2001 prices)

Envestra – Albury	2003	2004	2005	2006	2007	Total
Return on assets	1.7	1.7	1.6	1.6	1.6	8.3
Regulatory depreciation	0.8	0.8	0.8	0.9	0.9	4.2
Operating expenditure	1.2	1.2	1.2	1.2	1.1	5.8
Efficiency carryover	-	-	-	-	-	-
Tax wedge	0.0	0.1	0.1	0.1	0.1	0.4
TOTAL REVENUE[a]	**3.7**	**3.7**	**3.7**	**3.8**	**3.8**	**18.6**
Envestra –Victoria						
Return on assets	45.5	45.8	46.1	46.3	46.5	230.2
Regulatory depreciation	22.6	23.5	24.6	25.7	26.8	123.1
Operating expenditure	36.3	35.9	35.6	35.2	34.9	177.9
Efficiency carryover	-	-	-	-	-	-
Tax wedge	0.4	1.2	1.8	2.4	2.9	8.8
KDt factor	0.7	-	-	-	-	0.7
TOTAL REVENUE[a]	**105.4**	**106.5**	**108.1**	**109.7**	**111.1**	**540.8**
Multinet						
Return on assets	53.2	53.8	54.3	54.7	55.0	270.9
Regulatory depreciation	31.8	33.7	34.9	36.2	37.4	174.0
Operating expenditure	39.3	38.9	38.5	38.1	37.7	192.5
Efficiency carryover	3.9	3.3	8.5	3.3	-	19.0
Tax wedge	2.7	3.6	4.1	4.6	5.0	20.0
KDt factor	5.7	-	-	-	-	5.7
TOTAL REVENUE[a]	**136.5**	**133.2**	**140.3**	**136.9**	**135.1**	**681.9**
TXU						
Return on assets	50.8	51.8	52.8	53.7	54.7	263.7
Regulatory depreciation	24.3	24.7	25.0	25.4	25.7	125.1
Operating expenditure	40.5	40.1	39.7	39.3	38.9	198.7
Efficiency carryover	-	-	-	-	-	-
Tax wedge	0.2	0.5	1.1	1.6	1.9	5.3
KDt factor	2.8	-	-	-	-	2.8
TOTAL REVENUE[a]	**118.6**	**117.1**	**118.6**	**120.0**	**121.2**	**595.5**

A Columns may not add due to rounding

The X factors adopted by the Commission then reflect its conclusions regarding the revenue stream referred to above, and its conclusions regarding the forecast level of demand (based on 'normal' weather conditions) for the next access arrangement period. The X factors adopted for this Final Decision are provided in table 3.3.

TABLE 3.3
FINAL DECISION: REFERENCE TARIFF P^0 AND X FACTORS TO APPLY TO EACH DISTRIBUTOR, 2003-07

	P^0	X
Envestra Albury	2.6	1.0
Envestra Victoria	9.9	1.0
Multinet	2.0	-0.7
TXU	2.0	-0.5

This table implies a reduction in weighted average prices for Envestra Albury of 2.6 per cent in 2003 in real terms from current prices, 9.9 per cent for Envestra Victoria and 2.0 per cent for Multinet and TXU. It also implies a further reduction in weighted average prices in each subsequent year of the access arrangement period of 1.0 per cent for Envestra's Albury and Victorian network, with an increase of 0.5 per cent for and 0.7 per cent for TXU and Multinet respectively.

The weighted average price changes included in this Final Decision reflect the change required to existing prices to bring the revenue that is forecast under reference tariffs over the next five years into line with the stream of revenue (total revenue) calculated for each of the distributors by the Commission in accordance with the Gas Code. The latter stream of revenue has been calculated with reference to a return on the value of their investments in the regulated activities, a return of that investment over time through depreciation and operating and maintenance expenses. A forecast of sales over the next five years is then required to forecast the revenue expected to be received under reference tariffs.

As the same principles have been applied to derive the required weighted average price changes for each of the distributors, the differences across the distributors reflect the unique characteristics of each business. Moreover, as the same principles were used to set the current reference tariffs in 1998, the required price changes can also be explained with reference to the combination of two factors. These are: the differences between the 1998 forecasts of revenue for 1998-02 and the outturn results; and the differences between the 1998-02 revenue benchmarks and the revenue benchmarks for the 2003-07 period. These two factors are considered in turn.

However, the required weighted average price changes reflect the interaction of a number of complex factors, and so it is not possible to dissect the price changes with surgical precision. Accordingly, the Commission cautions against an overly detailed reliance on the explanation for the relative price changes presented below.

Difference between forecast and actual revenue in 2002

Under its approved prices for 2002, Envestra would have earned substantially more revenue than forecast in the current year *if the weather had been normal*. In reality, Envestra has not actually captured this additional revenue (as a result of Victoria's unusual run of warm winters). However, as revenue over the 2003-07 period has been forecast on the assumption that *normal* weather prevails, differences in revenue under *normal* weather conditions are relevant for the assessment of the new prices.

Under their approved prices for 2002, TXU also would have earned more revenue than the 1998 forecast in 2002 under normal weather, whereas Multinet would have earned substantially less than the 1998 forecast in 2002. However, for both of these distributors, the rebalancing control precluded them from raising prices to the full extent permitted under the revenue yield price control. As this revenue loss has been included in the revenue benchmarks for the distributors over the next regulatory period, the effect on the required price changes is two-fold. First, as prices are starting from a lower point (over 4 per cent lower for Multinet), any required price reduction to align forecast revenue with the new revenue benchmarks would be reduced. Secondly, by adding the loss of revenue as a result of the rebalancing control (the 'K' factor) to the revenue benchmarks, any required price reduction itself is ameliorated.

The reasons that revenue yield form of price control has permitted more revenue than forecast to be received in 2002 are complex. While two of the distributors (TXU and Multinet) have served more growth than forecast over the period, Envestra has served less. One of the reasons is forecast error in the mix (rather than the total) of demand over the period, which has led to permitted average prices rising more than forecast. The levels of 'rounding' employed when setting the current revenue yield controls (of the order of 0.5 percentage points to the annual X factor) also may have contributed to the differences between forecast and actual revenue (under normal weather conditions).

Difference between the 1998-02 and 2003-07 forecasts

For Envestra, the new revenue benchmarks are only marginally lower than the benchmarks set at the time of the 1998 Review. Envestra has spent less capital expenditure than forecast in the 1998-02 period, and this Final Decision forecast an even lower level of capital expenditure over the 2003-07 period. This has contributed to a fall in the return on assets and depreciation components of its revenue benchmarks over the next period.[149]

For TXU, the revenue benchmarks for the 2003-07 period are substantially higher than those set for the 1998-02 period. This reflects, for the most part, TXU's substantially higher level of operating expenditure over the 1998-02 period than forecast, which has been reflected in the 2003-07 forecasts. TXU has also undertaken significantly more capital projects than forecast over the 1998-02 period, and a forecast of an even higher level of capital expenditure has been adopted for the 2003-07 period. Both of these factors contribute to the increase in the 2003-07 revenue benchmark compared to the 1998-02 benchmarks.

[149] The reduction in the cost of capital estimated by the Commission in this Final Decision conpared to that in the 1998 Decision has also contributed to the fall in its return on investment line-item compared to the 1998 forecasts. However, this factor is common across the three distributors.

For Multinet, its revenue benchmark for the 2003-07 period is higher than the benchmark for the 1998-02 period. This increase in the benchmark can be explained by the fact that it managed to serve substantially more customers than forecast over the 1998-02 period, while also reducing its overall level of capital expenditure. The combination of these two factors has led to it receiving a substantial 'efficiency carry-over' as its share of these efficiency gains. At the same time, the Commission has accepted forecasts of a substantial rise in its capital expenditure program compared to the 1998-02 forecasts (and compared to existing levels), which has also contributed to the increase in revenue benchmarks for 2003-07 compared to 1998-02.

Finally, in interpreting the X factors, a number of other matters need to be taken into account. First, the Commission has decided to incorporate an annual adjustment for the actual licence fees paid by each distributor onto the 'base' prices referred to above, rather than including an allowance for these fees in the revenue benchmarks.

Secondly, the distributors in Victoria and Albury are in the process of implementing systems to support full retail contestability. In Victoria, the Governement has put in place a separate regulatory instrument to allow for the reovery of these costs. This will result in a charge in excess of the price for the distribution of gas referred to above. Moreover, the Commission has replicated the Victorian arrangements for Albury, so that these costs will also be recovered through a charge in addition to the distribution charges discussed above.

3.3 Operating and maintenance expenditure

3.3.1 Introduction

Forecasts of operating, maintenance and other costs incurred in the delivery of the relevant services (referred to as non-capital costs in the Gas Code) are an important component of total revenue, which is used to establish the reference tariffs to apply for the five years from January 2003. These forecasts will also provide the point of reference for determining the efficiency gains made over the next regulatory period.

Section 8 of the Gas Code sets out the principles that the reference tariffs contained in a distributor's Access Arrangement must comply with. Section 8.1 sets outs the specific objectives that the calculation of reference tariffs should be designed to achieve namely:

- providing the service provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the reference service over the expected life of the assets used in delivering that service;
- replicating the outcome of a competitive market;
- ensuring the safe and reliable operation of the pipeline;
- not distorting investment decisions in pipeline transportation systems or in upstream and downstream industries;
- efficiency in the level and structure of the reference tariff; and

- providing an incentive to the service provider to reduce costs and to develop the market for reference and other services.

To the extent that these objectives conflict, the Commission may determine the manner in which they can be best reconciled or which of them should prevail. Where the Commission does so, it must apply the principles set out in section 2.24 of the Gas Code.

Sections 8.36 and 8.37 set out the provisions specifically related to recovery of operating and maintenance costs (non-capital costs). Section 8.36 defines non-capital costs to be the operating, maintenance and other costs incurred in the delivery of a reference service. Section 8.37 states that reference tariffs may provide for the recovery of all non-capital costs (or forecast non-capital costs, as relevant) except for any such costs that would not be incurred by a prudent service provider, acting efficiently, in accordance with accepted and good industry practice, and to achieve the lowest sustainable cost of delivering the reference service.

In determining whether to approve reference tariffs, the Commission must be satisfied of the various factors listed in section 8.2 namely:

- the revenue to be generated from the sales (or forecast sales) of all services over the access arrangement period (the total revenue) should be established consistently with the principles and according to one of the methodologies contained in section 8;
- to the extent that the covered pipeline is used to provide a number of services, that portion of total revenue that a reference tariff is designed to recover (which may be based upon forecasts) is calculated consistently with the principles contained in section 8;
- a reference tariff (which may be based upon forecasts) is designed so that the portion of total revenue to be recovered from a reference service (referred to in paragraph (b)) is recovered from the users of that reference service consistently with the principles contained in section 8;
- incentive mechanisms are incorporated into the reference tariff policy wherever the relevant regulator considers appropriate and such incentive mechanisms are consistent with the principles contained in section 8; and
- any forecasts required in setting the reference tariff represent best estimates arrived at on a reasonable basis.

In terms of assessing compliance with the requirements of section 8 of the Gas Code, section 8.49 states that the Commission may determine its own policies, subject to the requirement for public consultation.

This section sets out the Commission's detailed consideration of the responses received in relation to its Draft Decision and the assumptions adopted for the Final Decision. It first outlines the distributors' proposals (section 3.3.2) and then provides an overview of the approach that was adopted by the Commission in its *Draft Decision* (section 3.3.3). It also outlines its further analysis of the responses received in relation to that approach and sets out its conclusions as to the approach used to assess the distributors' proposals in this Final Decision.

Sections 3.3.4 to 3.3.6 provide the Commission's consideration of the responses that have been received in relation to the Draft Decision that relate to specific expenditure items and issues. The final assumptions adopted by the Commission are presented in section 3.3.7.

3.3.2 Distributors' proposed forecasts

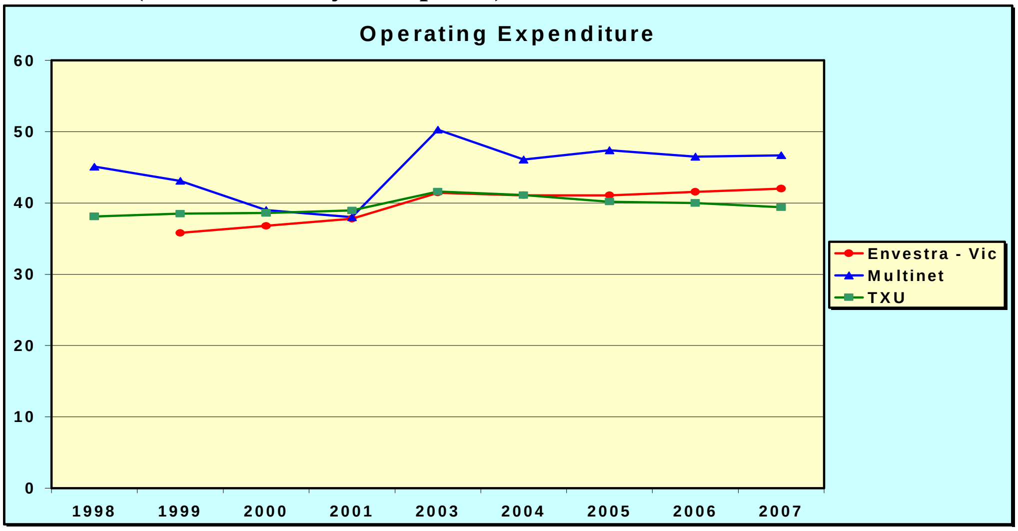
The operating expenditure forecasts for the period 2003-07 proposed by the distributors in their Access Arrangement Information are presented in the table below. In some instances, the distributors have made certain adjustments to these proposed forecsts during the review process. These adjustments are identified in the discussion of specific expenditure issues.

TABLE 3.4
DISTRIBUTORS' PROPOSED OPERATING EXPENDITURE FORECASTS 2003-07 ($ million in July 2001 prices)

	2003	2004	2005	2006	2007
Envestra Albury	1.8	1.8	1.8	1.8	1.8
Envestra Victoria	42.9	42.6	42.7	43.2	43.8
Multinet	50.3	46.1	47.4	46.5	46.7
TXU	45.3	41.1	40.2	40.0	39.4

The amounts that each distributor has forecast for the efficient cost of operating and maintaining their networks for 2003 exceed the amounts reported as spent on this activity in 2001. In particular, Multinet has forecast a 25 per cent increase. The increases put forward in the distributors' initial Access Arrangement Information are shown in the below.

FIGURE 3.5
DISTRIBUTORS' ACTUAL AND PROPOSED OPERATING EXPENDITURE 1998-2007 ($ million in July 2001 prices)



The reasons for the projected increases vary to some extent between the distributors and reflect the distributors' views about the costs associated with new functions, future levels of activity and changes in various input costs. These include costs associated with metering, network marketing and full retail contestability, and insurance premiums and licence fees. In the case of TXU and Multinet, the forecasts include the costs associated with the implementation of a Guaranteed Service Level (GSL) payments scheme.

The Commission's approach to assessing these forecasts in the Draft Decision is presented below, together with the Commission's consideration of the comments received in response and its conclusions regarding the approach used for this Final Decision.

3.3.3 Approach to assessing proposed forecasts

Section 8.49 allows the Commission to determine its own policies for assessing whether the proposed reference tariff complies with the requirements of section 8, subject to undertaking public consultation. In addition, section 8.2 of the Gas Code requires (amongst other things) the Commission is satisfied that the forecasts used to establish reference tariffs are the 'best estimates arrived at on a reasonable basis'. The Commission outlined its proposed approach to assessing operating expenditure forecasts in consultation prior to the distributors having to submit their proposed Revisions and the Commission adopts that proposed approach in this Final Decision.[150]

The approach adopted by the Commission relies on the proposition that the incentives provided by the regulatory framework will generally lead to efficient expenditure levels, and accordingly, the expenditure incurred in 2001 provides a *base level* that can be used as the foundation for establishing the estimate for 2003-07. The focus of the assessment process is then on any *step change* in expenditure levels that may be required to reflect changes in the scope of distribution activities from one period to the next, and the overall underlying *trend* in expenditure.

The reason for adopting this approach is that it avoids the information problems associated with attempting to establish a forecast using more information intensive approaches. This reasoning is consistent with the comments made in a joint industry submission to the Productivity Commission:

> Overall, we submit that the search for efficient operational costs by analytical means is almost certain to fail in practice given the information uncertainty facing regulators. It is, in other words, ultimately likely to prove futile and socially harmful. Additionally, it is our view that that search should be unnecessary in the presence of a properly constructed regime based on incentive regulation. The theoretical basis of incentive based regulation is that efficient costs will be revealed through the operation of properly structured incentives – it is not necessary to seek to determine those costs by other means such as regulatory inquiry.[151]

---

[150] Consultation Paper No. 1; Position Paper, pp.50-53; Further Guidance to Gas Distributors, pp.44-46.

[151] National Economic Consulting Group, Joint Industry Submission on the Productivity Commission's Review of the National Access Regime, 5 June 2001, DR 76. p.37 Quoted in ibid p.51.

The existence of the information problems referred to above underpins the Commission's view that this approach provides a reasonable basis upon which to establish the best estimate of efficient costs going forward. Under the Commission's approach, the potential exposure to these information problems is limited to estimating the cost impacts of changes in the scope of distribution functions or activities and the establishment of the overall trend in expenditure. At the same time, it avoids more complex and detailed alternatives, which the Commission does not consider would overcome these information issues.

The Commission explained how it would take account of any changes in the scope of distribution activities during the preliminary consultation process.

> The Office considers that the most appropriate means of taking into account the implications of a change to distributors' obligations or functions is to adjust the underlying expenditure trend to reflect an unbiased estimate of the additional (or reduction in) cost associated with expanding (or reducing) these obligations or functions. While this will inevitably reflect an estimate or benchmark, it is considered far simpler (and ultimately less resource intensive and risky for distributors) to adopt an external benchmark or estimate just for the change in distributors' obligations or functions, as opposed to attempting to derive a benchmark for all of their activities.[152]

Similarly, the Commission also explained how it proposed to take account of the trend in operating expenditure:

> In principle, this assumption should reflect an unbiased assumption about the rate of change in expenditure for an efficient company over the period. A number of factors may be relevant, including expected productivity improvements, changes in the price of the firms' inputs, as well as the impact of demand growth on operating expenditure.
>
> …
>
> Some of the factors the Office considers may be relevant include historical trends in gas distribution operating expenditure, price indices relevant to the inputs employed for this function, and information on the relationship between operating expenditure and demand growth.[153]

The reference to an inevitable reliance on an estimate or external benchmark to take into account the costs associated with changes in distributors' obligations, and the implicit reference to the use of benchmarks (such as historical trends and price indices) for establishing the trend, reflects the information problems associated with any attempt to establish precise firm-specific estimates. Given the existence of information asymmetry, the Commission considers that the use of reported actual results to establish a base-level of expenditure and then external benchmarks to take account of any change in functions and the trend in expenditure is more likely to produce the best estimate of costs arrived at on a reasonable basis (as required by section 8.2(e)).

152 Position Paper, p.52, Further Guidance Paper, p.45.
153 Position Paper, p.52.

Given this information asymmetry, the Commission also does not consider that attempts to assess firm specific expenditure forecasts would lead to 'best' forecasts, nor that such an approach is 'reasonable' as required by section 8.2 of the Gas Code. Rather, given these constraints on regulatory decision making, it considers that its approach of using incentives to 'reveal' a starting point for expenditure and then using benchmarks to allow for changes in obligations and the trend in expenditure is likely to produce better forecasts and is a more reasonable basis.

As noted above, the Commission is also required to ensure that the expenditure forecasts exclude those costs that 'would not be incurred by a prudent service provider, acting efficiently, in accordance with accepted and good industry practice, and to achieve the lowest sustainable cost of delivering the reference service'.[154] The concepts of 'prudent service provider', 'acting efficiently' and 'good industry practice' are benchmarks themselves against which the Commission is required to assess the distributors' proposals. After having regard to public consultation on the matter, the Commission considers that using incentives to reveal an efficient and prudent starting point, and then external benchmarks to allow for changes in obligations and the trend in expenditure is the most appropriate policy (pursuant to section 8.49 of the Gas Code) for meeting the requirements of section 8.37.

On balance, the Commission considers its proposed approach for assessing the distributors' operating expenditure forecasts remains appropriate, having regard to the relevant provisions in the Gas Code.

The assessment undertaken for the Draft Decision was tailored around the three main components of the approach foreshadowed in the preliminary consultation process. That is, the establishment of actual expenditure for 2001, adjustments for any step changes due to changes in scope from one period to the next and the application of a trend for the remainder of the period.

The Commission adopted the base level expenditure reported by the distributors for 2001 and applied the ongoing trend reflected in the annual projections of all three distributors in total. However, it did not accept the distributors' proposed forecasts in relation to the step change predicted to occur from 1 January 2003. As a consequence of this, and several other factors, the Commission adopted operating expenditure forecasts in the Draft Decision that were lower than the forecasts submitted by the distributors.

The Commission has consulted further on the assumptions adopted in the Draft Decision and has carefully considered the responses it has received from the distributors and other interested parties, including the views expressed at the public forum and the additional material that has been submitted. Details of its consideration of these responses are presented below, commencing with issues relating to the overall approach adopted by the Commission before turning to those that relate to specific expenditure items and issues.

[154] Section 8.37 of the Gas Code.

Comments on the Commission's approach

The distributors' submissions appeared to generally support the Commission's more pragmatic and less information-intensive approach and are directed more to the way in which the Commission has applied its approach – in particular, they focused on the extent to which the assumptions used in the Draft Decision properly accounted for the step changes in expenditure from 2001 to the 2003-07 period.

For instance, Multinet, while favouring an even less information-intensive approach than that of the Commission, labelled the Commission's approach 'broad-brush'. It claimed that the Commission had not had regard to any material changes (positive and negative) in scope, which may result in future forecasts of efficient expenditure being materially different to recent historic actual expenditure or to any material cyclical drivers of costs.[155] As a consequence, Multinet argued that the Draft Decision did not comply with section 8.2(e) of the Gas Code. It also suggested that failing to take account of material changes in scope is inconsistent with the Commission's statement in its Position Paper regarding the importance of taking these factors into account:

> The Office also accepts the concerns expressed in all of the submissions above that it would be unreasonable in general just to use the expenditure level from one period to the next with no account taken of the increase (or reduction) in cost associated with the addition (or removal) of obligations or functions. This matter is particularly relevant for the forthcoming review given that distributors will undertake additional functions as part of the implementation of FRC.[156]

The Commission does not accept that it has failed to have regard to the factors identified in Multinet's response, nor does it consider that there is any inconsistency with the statements made in its Position Paper. The Draft Decision details of the Commission's consideration of these matters, including the reasons for not adopting Multinet's proposed forecasts and the costs associated with any additional obligations arising as a result of the introduction of FRC. An important factor is the Government's separate arrangements allowing distributors to recover certain FRC costs, which was implemented *after* the release of the Position Paper. Accordingly, many of the Commission's comments about the importance of accounting for FRC costs in calculating reference tariffs are now no longer relevant.

Multinet also stated that if a distributor could show that its forecasts are 'reasonable in all circumstances', then the regulator should accept these forecasts as complying with section 8.2(e) of the Gas Code.[157] This interpretation suggests that section 8.2(e) requires the Commission to adopt 'reasonable' forecasts, whereas in the Commission's view the clause requires it to be satisfied that the forecasts used to establish reference tariffs represent the 'best estimates' arrived at on a reasonable basis. The Commission has previously explained the reasons for adopting its approach and has also presented them above.

155 Multinet, Response to Draft Decision, p.41.
156 Position Paper, p.51.
157 Multinet, Response to the Draft Decision, pp.40-41.

Envestra stated that the Commission's approach in the Draft Decision is inconsistent with section 8.37 of the Gas Code in that it fails to provide for the recovery of costs of a prudent service provider. Envestra's reasons included that the Commission's methodology relies on a starting point that is incorrect and its adjustments for scope and 'other changes in the business environment' are incomplete. Notwithstanding whether or not Envestra's forecasts reflect the costs that would be incurred by a prudent service provider, it should be noted that section 8.37 states that reference tariffs *may* provide for the recovery of forecast operating costs *except* any such costs that would not be incurred by a prudent provider. [emphasis added] Ultimately, the Commission must consider a range of factors set out in the Gas Code, including the objectives and other requirements of section 8 in deciding whether a reference tariff should recover costs that would be incurred by a prudent service provider.

Both Multinet and Envestra argued that the Commission's assessment of changes in scope was unduly narrow and that the annual downward trend in expenditure proposed in the Draft Decision was too aggressive. Each of their responses indicated the matters that they believed the Commission needed to consider in forming a view about the change in costs from the first period to the next. Multinet refered to the full effect of material changes in costs that are 'beyond the control of the company' and provided examples such as insurance premiums, contracts with external providers, customer-related costs due to the introduction of FRC, costs associated with ageing assets and savings achieved in the procurement of services.[158] Similarly, Envestra suggested that an appropriate approach is to pose a number of questions including the extent to which: the changes in costs are outside the distributor's control, would be incurred by a prudent provider, are material and do not relate to imprudent business decisions.[159]

Both Multinet and Envestra's proposed approaches seek to introduce criteria for assessing whether changes in individual cost items should be reflected in reference tariffs. However, in the Commission's view, many of the factors mentioned do not relate to changes in the scope of distribution functions. That is, they include proposed changes in costs associated with functions that would have been undertaken in any event, such as the need to acquire insurance, renegotiate contracts with external providers, comply with changes to superannuation and address ageing assets.

The Commission acknowledges that reference tariffs should be designed to provide the distributors with the opportunity to recover efficient costs over the life of the relevant assets amongst other design features set out in the Gas Code, and accordingly, it needs to consider factors that are expected to impact on costs over time.

A relevant consideration is whether the Commission is able to obtain the necessary information from distributors to enable it to assess fully whether distributors have identified all of the items that may have changed. This includes, for example, assessing items that were incurred in 2001 (and therefore captured in the base level forecast) or items for which costs are to be expected to reduce over time. The general rationale for the Commission's approach in the Draft Decision is broadly consistent with Envestra's comment in relation to a claimed step change in insurance costs:

158 ibid, p.41.
159 Envestra, Response to Draft Decision, p.27.

> (it) accepts the general economic rationale that some operating cost items will increase and others will decrease and, that in the majority of cases, these will be picked up in the productivity trend…[160]

The approach put forward by the Commission in consultation undertaken prior to this review and subsequently used in the Draft Decision noted the exception to 'the majority of cases' is the costs associated with changing functions. The distributors' approach advocates separate allowances for a broader range of items.

A number of comments have been made related to the extent to which the Commission can rely on the incentive properties of the existing regime, particularly the inference that existing expenditure levels should be regarded as efficient. On the one hand, the Energy Users Coalition of Victoria called for greater scrutiny of past and projected costs, and suggested that it was inappropriate to rely on the figures reported by the distributors:

> We note that the Commission appears not to have considered that it needs to undertake efficiency assessments of each distributor's performance during the 1998-2002 access period nor is there a rigorous scrutiny of opex costs forecasts for 2003-07. EUCV is of the view that by the Commission taking such a view, it is taking theoretical economics to extremes, and overlooks the Gas Code's requirements to benchmark performance and to drive improved performance of the regulated business by the 'competition by comparison' principles used by the ORG.[161]

On the other hand, Envestra stated that the reported expenditure results were lower than efficient levels:

> Properly structured incentives do not exist in the current regulatory period. This is predominantly because the expenditure forecasts against which the incentives measured were set unrealistically low, and actual revenue was lower than forecast. One consequence of this is that Envestra was forced to defer some expenditure (notably network marketing). Such distortions must be taken into consideration by the Commission, which must accept that the industry is still some time away from a true incentive-based regime.[162]

Under the CPI-X approach, the X factors that apply each year throughout the access arrangement period are not adjusted within that period. The source of the incentives to pursue gains extends from the fixed nature of these price caps, not the particular assumptions used to set them in the first place. The caps remain in place for the duration of the period irrespective of whether the assumptions used to establish them turn out to be favourable or unfavourable to the distributor. As such, the Commission considers the incentive properties of the regime are sufficient to infer that operating (and capital) expenditure approximates levels that would be incurred by a prudent service provider operating efficiently.

The Commission has carefully considered the comments received in relation to the approach that it has adopted for the Draft Decision and provides its concluding remarks below.

160 ibid, p.28.
161 Energy Users Coalition of Victoria, Response to Draft Decision, 29 August 2002, p.8.
162 Envestra, Response to Draft Decision, p.27.

Conclusions

Under the Gas Code, the Commission must be satisfied that the forecasts used in establishing reference tariffs are the best estimates arrived at on a reasonable basis. In May 2001, the Commission put forward for public comment its proposed approach to establishing and assessing forecast operating expenditure for 2003-07. The Commission has adopted this approach in its Final Decision. This approach is to adjust the trend for the impacts of changes in functions from one period to the next, with the quantum of any such adjustments determined with reference to unbiased estimates based on industry benchmarks.

Much of the concern regarding the Commission's approach relates to the establishment of the underlying level of operating expenditure and the subsequent 'step change' adjustments to that level. The distributors have proposed adjustments to the trend to account for changes in particular cost items (irrespective of whether the change relates to different functions or not), with the quantum determined by a heavily weighted reference to firm-specific estimates. The Energy Users Coalition of Victoria has proposed a more extensive assessment of the extent to which reported expenditure reflects efficient levels.

As noted above, the Commission's concern with the distributors' proposed approach is that it creates the potential for estimates to be adopted that favour the distributors rather than customers as a consequence of the distributors' information advantages and their natural incentives to submit estimates that are favourable to the distributors. In particular, it enables the distributors to identify only those items where they can establish a case that costs are increasing. This information asymmetry, amongst other things, has led to the Commission relying on the costs that would be incurred by a prudent service provider acting efficiently being 'revealed' by the distributors through the operation of the incentives inherent in a CPI-X approach. While the Commission notes the Energy Users Coalition of Victoria's view that there is a need for a more comprehensive review of efficiency, it believes that the long run outcome of effectively implementing and relying on incentive regulation best meets the objectives of the Gas Code.

The Commission has carefully considered the responses to the Draft Decision, including the additional material provided in relation to projected increases for certain inputs required to fulfil existing functions. For the purpose of this Final Decision, the Commission has considered and discussed the matters raised in relation to operating expenditure as:

- the establishment of a base level expenditure forecast;
- the level of marketing activity;
- the incremental costs of new obligations; and
- the future trend (including step changes proposed in certain input costs).

The following sections discuss each of these matters, with the conclusions in the relation to the overall assumptions adopted for this Final Decision discussed in section 3.3.8.

3.3.4 Base level expenditure

In the Draft Decision, the Commission established a base level expenditure for 2003 that reflected the 2001 reported actuals adjusted for a number of factors. These adjustments reflected the Commission's need to exclude licence fees from the operating expenditure forecasts as a result of its decision to include a separate licence fee adjustment in the price controls, the recovery of correction factors arising from the existing price control arrangements and the expenditure trend between 2001 and 2003.

Given the reliance placed on step changes and trends from *existing* levels to establish an operating expenditure benchmark, it is important to verify the distributors' reported actual expenditure for 2001. The Gas Code defines operating expenditure (or non-capital costs) to be the operating, maintenance and other costs *incurred* in the delivery of a reference service. It is therefore important to ensure that the reported expenditure levels accurately represent expenditure that is attributable to the delivery of reference services, and not to other activities.

Unlike electricity distribution, there are no regulatory accounting guidelines in place for gas distribution reference services. As such, the reported expenditure levels submitted by each distributor have not been derived according to a set of guidelines issued or approved by the Commission. In addition, the ownership and organisational arrangements of each distributor differ. Further, more than one-third of these costs relate to overheads. Together, these factors emphasise the importance of robust cost allocation processes.

For the purposes of the Draft Decision, the Commission indicated that it had adopted an assumption that the distributors' reported actual costs accurately reflect the costs incurred in providing reference services. However, it also noted that it proposed to verify the calculations used prior to the Final Decision in consultation with the distributors. To this end, the Commission engaged BDO Consulting to undertake a more detailed examination in consultation with the distributors. The issues to emerge from the verification process and the responses to the Draft Decision are presented and considered below.[163]

Envestra's contract with Origin Energy Asset Management

An issue of concern raised in the Draft Decision is the management fee component of the contract between Envestra and Origin Energy Asset Management (OEAM), which was entered when each organisation was part of a single entity. This fee is paid as a fixed percentage of revenue (3 per cent) rather than linked to the actual management costs incurred. The Commission expressed the view that to the extent that this revenue-sharing arrangement represents a share of profits, it would consider this to have been provided for already by the return on capital assumptions used in the calculation of reference tariffs. Envestra did not comment on this issue in its response to the Draft Decision.

[163] Multinet and Envestra raised issues regarding the appropriateness of using 2001 in light of the cyclical nature of some costs (metering and five-yearly regulatory reviews respectively).

An examination of that contract suggests that the character of the payment does not relate to the costs incurred by OEAM. Under the terms of the contract Envestra pays all costs and disbursements reasonably incurred or outlaid by OEAM in the performance of its obligations under the terms of the Agreement. The separate entitlement to a management fee based on 3 per cent of total network revenue is in addition to the entitlement to be reimbursed all costs and disbursements. On this basis, it would appear that the payment relates to a profit-sharing arrangement, rather than the costs of undertaking asset management activities.

However, an important consideration is whether the total costs to a service provider of meeting the costs incurred by a contractor and also paying a revenue-based fee, were less than the total costs that would have been incurred in any event.

The Commission has been advised by BDO that representatives from Envestra have explained that the management fee reflects the cost advantages that accrue to Envestra as a result of Origin Energy undertaking the prescribed asset management activities relative to the alternative of these activities being undertaken by Envestra.

In order to comply with section 8.37 of the Gas Code, the Commission needs to be satisfied that the inclusion of this payment does not result in reference tariffs that are recovering costs that a prudent service provider would not be incur. That is, where a prudent service provider is acting efficiently, in accordance with accepted and good industry practice, and to achieve the lowest sustainable cost of delivering reference services.

The assessment of compliance with this section requires an assessment of the costs to be recovered by the proposed reference tariffs relative to those that would be incurred by a 'prudent service provider' rather than relative to the costs that would arise from the 'in-house' alternative mentioned above. The Commission would consider that for this to be satisfied the arrangement would need to be subjected to a full and proper market test for the provision of these services. The Commission notes that the arrangements were entered into when both Origin Energy and Envestra formed part of a single entity. As such, the Commission is not able to assess whether the total payment to Origin Energy (the 3 per cent share of revenue and the reimbursement of costs) is commensurate with the total payment that would arise from a contract entered into pursuant to an arm's length competitive tender process.

However, the Commission notes that Envestra's reported actual costs for 2001, after adjustments made in this section of the Final Decision, compare favourably with the benchmarks used to establish the existing reference tariffs. It should also be noted that the Commission considered that these initial benchmarks were at the low end of the reasonable range.[164].

Hence, while the Commission is of the view that the most appropriate assessment would be to conduct a market test through a competitive tender process, the reported expenditure relative to the initial benchmarks suggests that the outcomes are not inconsistent with the expenditure that would have been prudently incurred by an efficient service provider.

164 1998 Gas Distribution Price Review, p.69

For the purposes of this Final Decision, the Commission has included the payment in the operating expenditure benchmark used to calculate Envestra's reference tariffs. In adopting this conclusion the Commission remains concerned about the extent to which it can rely on costs reported pursuant to contracts entered into by related parties. The Commission is of the view that the long-run interests of users (section 2.24(f) of the Gas Code) will not be served by contracts entered into by related parties for the provision of most of the fundamental activities required to provide reference services, without a competitive tender process. The Commission also considers that such arrangements are not consistent with the public interest in having competition in markets, including the provision of asset management services (section 2.24(e) of the Gas Code).

Financial transaction costs

The process of verifying the basis of establishing the 2001 reported expenditure identified that Envestra had included amortised financing transaction costs and related agents' fees totalling $3.9 million. In a further submission, Multinet noted that the ACCC's Draft Decision regarding GasNet's proposed access arrangement allowed for the inclusion of equity raising transaction costs in its operating expenditure assumptions.

The Commission is of the view that, for the reasons explained in section 3.6, the costs associated with debt and equity are more properly accounted for when considering the cost of capital. Accordingly, the Commission has excluded the amounts included by Envestra in its 2001 operating expenditure from the base level operating expenditure and are assessed, together with the amounts proposed by Multinet, in section 3.3 dealing with capital expenditure matters.

Capitalisation

Envestra expressed concerns over the Commission's reliance on its previous capitalisation policy:

> Envestra changed the capitalization policy in 1999 after it purchased the network. However, in preparing their April submission, Envestra adjusted actual expenditure to be consistent with the old capitalisation policy that was used to prepare the 1998 access arrangement forecasts. The change in capitalisation policy was treated as a change in scope as set out in the reconciliation provided to the Commission on 17 June 2002. However, Envestra's approach is inconsistent with the methodology proposed by the Commission and that used by other distributors. To apply the Commission's methodology correctly, Envestra's operating costs submitted in its 2 April submission need to be increased to be consistent with the current capitalisation policy and capital expenditure forecasts adopted by the Commission.[165]

165 Envestra, Response to Draft Decision, p.27.

The Commission has received further information from Envestra in relation to its policy and accepts the need to make the adjustments to its operating expenditure and capital base assumptions (section 3.5). As a result, it has adjusted the reported operating expenditure for 2001 upwards to account for the appropriate capitalisation policy by $1.50 million.

Licence fees

Under section 30 of the *Gas Industry Act 2001*, each of the Victorian gas distributors is required to pay licence fees as determined by the Minister for Finance, based on costs incurred by the Commission. In relation to the Albury network, Envestra pays licence fees to the NSW Government. The distributors' proposals included forecast licence fees and a change in tax pass-through provision that would potentially allow for adjustments to reference tariffs to reflect any change above the forecast levels.[166]

In its Draft Decision, the Commission noted the merits of providing more transparency in relation to recovery of its costs each year through licence fees. Rather than adopt a forecast and then provide for adjustments to be made where the forecasts proved to be incorrect, the Commission proposed an alternative whereby recovery of *actual* licence fees would be incorporated into the price control formula used to assess network tariffs each year. Under this arrangement, reference tariffs for a given calendar year would recover the fees paid for the preceding financial year.[167] Substantiation of the annual licence fees paid would occur as part of the annual tariff approval process.

As the distributors included an allowance in current reference tariffs for licence fees incurred over this period, the Commission noted in the Draft Decision that an adjustment should be made to remove the allowance made for the 2003-07 period. In addition, in view of the proposal to allow for 2003 reference tariffs to recover licence fees actually paid in the previous financial year, it also noted that an adjustment should be made to remove the allowance made for licence fees between July 2001 to December 2002 to prevent 'double-dipping'. However, as the 1998 decision did not separately identify forecasts of licence fees, the Commission has decided not to make such an adjustment for the July 2001 to December 2002 period.

The distributors generally supported the Commission's proposed approach of allowing licence fees to be recovered via a separate adjustment to the price controls, and adjusting the operating forecasts to reflect the separate recovery of these costs. However, they raised a number of issues related to the size of the adjustment.

In its Draft Decision, the Commission adjusted the reported results by $0.6 million for the Victorian distributors, and $0.04 million for Envestra Albury. The distributors noted that the correct figure for the Victorian distributors should have been $250 000. This has been corrected in the assumptions adopted for the Final Decision by adding $350 000 to the 2001 reported expenditure adopted in the Draft Decision.

---

166 Specifically, the distributors have proposed a change in the definition of a Relevant Tax to include 'any royalty, duty, excise, tax, impost, levy, fee or charge….'.

167 For example, the reference tariffs for 2005 would seek to recover actual licence fees paid for the 2003-04 financial year

Establishing a current 'base' figure from 2001 reported expenditure

Having established the appropriate base level expenditure for 2001, it is necessary to 'roll forward' this figure to establish an equivalent base figure for 2003. In its Draft Decision, the Commission derived its assumption of 2003 operating expenditure by adjusting reported expenditure for 2001 in the following way:

- applying the trend assumed in the existing reference tariffs between 2001 and 2002, to establish a figure for 2002;
- adjusting the 2002 figure for the underlying trend used as the assumption for the remainder of the 2003-07 period; and
- adding the correction factors to be recovered according the existing price controls (refer section 4.5).

These adjustments established a base figure for 2003. This was then adjusted further to account for the Commission's assumptions regarding the impact of step changes. The assumptions for the remainder of the 2003-07 period were then calculated by applying an ongoing annual trend.

Envestra commented that the Commission should take into account the costs associated with the customers who have connected between 2001 and 2003. All three distributors have claimed that costs such as insurance premiums have increased since 2001. These issues are considered in section 3.2, where the Commission has adopted a separate trend for the 2002 to 2003 in order to reflect these changes (rather apply the same trend to 2002 figure that is used for the 2003-07 access arrangement period).

Summary of adjustments

A summary of the adjustments referred to above is presented in the table below. These figures represent the underlying or *base level* expenditure, to which the assumed operating expenditure trend is to be applied after adjustments for step changes in the scope of distribution functions.

TABLE 3.6
FINAL DECISION: BASE LEVEL OPERATING EXPENDITURE ASSUMPTIONS ($ million in July 2001 prices)

	Envestra – Albury	Envestra – Victoria	Multinet	TXU
REPORTED 2001 COSTS (a)	1.2	37.2	37.4	38.4
Licence fee error		0.35	0.35	0.35
Capitalisation	0.05	1.50		
Finance cost amortisation		(3.90)	-	
Marketing (b)				0.26
BASE LEVEL 2001	**1.2**	**35.2**	**37.8**	**39.0**
Trend from 2001 to 2002 (c)	0.04	0.3	-0.0	-0.1
BASE LEVEL 2002	1.16	34.8	37.8	38.9
Step change for obligations	0.0	0.7	0.7	0.7
Trend from 2002 to 2003	0.03	0.8	0.8	0.8
BASE LEVEL 2003	1.19	36.3	39.3	40.4
Correction factors (d)	0.0	0.7	5.7	2.8
Trend from 2003-07	1%	1%	1%	1%
EXPENDITURE 2003-07	Presented in section 3.12			

(a) As adopted in the Draft Decision.

(b) Refer to marketing assumptions in section 3.3.5.

(c) The reduction assumed in the calculation of existing reference tariffs between 2001 and 2002.

(d) Correction factors are amounts to be allowed pursuant to the existing price controls. They correct for changes to the forecasts used in the annual tariff approval process.

3.3.5 Network marketing expenditure

An important consideration is the extent to which reference tariffs should incorporate the recovery of expenditure associated with marketing the use of gas.

Each distributor has reported expenditure associated with marketing activities for 2001 as follows: $1.1 million (Envestra Victoria), $1.3 million (Multinet) and $0.6 million (TXU). The distributors have argued that marketing expenditure is necessary to arrest the declining trend in gas consumption, which could potentially result in higher network charges per customer and/or unit of consumption. In terms of the 2003-07 forecasts, TXU and Envestra each proposed to increase marketing expenditure to approximately $3 million per annum, whereas Multinet did not propose any increase from the current levels.

In its Draft Decision, the Commission noted that with the exception of Multinet, the actual expenditure for 2001 year fell well short of the allowances that the Commission had included in reference tariffs in its 1998 decision.[168] This is reflected in the table below.

[168] The distributors advised that actual expenditure on marketing is not readily available prior to 2001.

TABLE 3.7
MARKETING EXPENDITURE FORECASTS ADOPTED IN 1998 FINAL DECISION ($ million in July 2001 prices)

	1998	1999	2000	2001	2002	2001 Actual
Envestra – Albury	-	0.03	0.03	0.03	0.03	**0.04**
Envestra – Victoria	4.9	4.1	4.1	4.5	4.3	**1.1**
Multinet	0.9	0.8	0.8	0.8	0.9	**1.3**
TXU	2.1	1.9	1.9	2.0	2.0	**0.6**

Envestra explained that the underspend relative to the assumptions used to set existing reference tariffs was due to actual outcomes with respect to other assumptions proving to be unfavourable to Envestra (for example, forecast revenue and other expenditure requirements).[169]

In the Draft Decision, the Commission did not assume increased marketing expenditure for 2003-07. In doing so, it noted that the distributors should have the incentive to undertake marketing to improve utilisation and consumption and thus earn extra revenue. It also considered that its assumptions related to future demand were consistent with the assumption of no increase in marketing activity, either by the distributors or retailers.

In response to the Draft Decision, TXU expressed concern that the Commission had not allowed sufficiently for costs associated with consumer education and promotion, arguing that, in the absence of price increases, such expenditure is necessary to maintain throughput volumes in order to recover the investment in the gas network. Further, it argued:

> In a regime of full retail contestability there is little, if any, incentive, for retailers to proactively inform customers of the advantages of natural gas over competing fuels. Under the building block approach currently used by the Commission, the benefit of any additional volume is fully and immediately passed to customers at the price reset. This means there is no incentive for a distribution company to invest in promotion of gas as a fuel.[170]

While TXU's initial proposal included a forecast of $3 million per annum for marketing and promotion, it has since submitted a revised plan, which it claims is more focused on offering incentives for customers to switch to gas appliances from other fuels.[171] This revised marketing plan has been budgeted at $0.86 million per annum. The Commission notes that this revised figure is only marginally higher than its actual marketing expenditure for 2001.

Envestra also raised concerns over the Commission's proposed approach to network marketing costs, claiming that:

---

169 Envestra, Response to Draft Decision, p.32.
170 TXU, Response to Draft Decision, p.9.
171 TXU, Further Response to Draft Decision, 23 August 2002, p.3.

- marketing expenditure partly depends on the availability of funds, which in 2001 was below budget;
- consumers are the real beneficiaries of such expenditure, while distributors are 'disincentivised', given that the increased load (and revenue) associated with such expenditure occurs over the life of new investment and tariffs are recalibrated at each reset to reflect additional load;
- gas distributors 'have to work much harder to secure market share than electricity businesses'[172], which is further exacerbated by the Government's policy of subsidising rural electricity users and anecdotal evidence that declining gas marketing expenditure has led to falling demand; and
- the Commission's outlook on network growth is at odds with its marketing expenditure benchmarks, given competitive issues (see previous point), the current transition from the Gas and Fuel Corporation monopoly to an environment of individual privatised businesses, and the demonstrated positive relationship between marketing and demand growth.[173]

With respect to the relationship between marketing and demand growth, Envestra submitted a study of the statistical relationship between United States gas distributors' sales expenditures and residential gas consumption in response to the Draft Decision.[174] The study found a statistically significant relationship in the United States between marketing expenditure and delivery volumes per residential customer, but cautioned that the magnitude of impacts might differ between the United States and Australia. Envestra maintained that its marketing program would require expenditure of $2.7 million per annum.

Envestra also questioned whether marketing expenditure for gas distribution should be less than electricity distribution, noting that gas is a 'fuel of choice'. It also noted that the assumptions adopted by the Commission's in its 2001 Electricity Distribution Price Determination were higher than the amounts adopted in its gas Draft Decision.[175] Similarly, TXU noted the Commission's different assumptions for gas and electricity, and indicated that the ACCC had found that gas consumption is sensitive to electricity prices, whereas electricity consumption is not sensitive to gas prices.[176]

172 Envestra, Response to Draft Decision, p.34.
173 ibid.
174 ibid., Attachment 1.
175 ibid., pp 34-35.
176 TXU, Response to Draft Decision, p.9.

However, the Commission notes that the differences between the electricity decision and the gas Draft Decision reflect industry-specific considerations, rather than an inconsistency in the Commission's approach. For instance, the key 'marketing' activity for electricity distribution relates to communication with customers regarding the services that they are already receiving. An important example is the provision of information concerning bushfire risks in rural areas, which explains why the assumptions adopted for the two distributors serving those areas include higher amounts than the three distributors that serve urban areas. In gas distribution, TXU and Envestra have put forward proposals that relate to the need to promote the use of natural gas, which relates to a different activity to that considered in relation to electricity distribution.

In any event, the amounts adopted for electricity are not universally higher than those adopted in the Commission's Draft Decision. As noted, the assumptions vary to account for rural-urban differences amongst other things, and range from $3.9 million over 5 years for United Energy to $21.6 million for TXU.[177] As noted above, TXU submitted a revised plan subsequent to its response to the Draft Decision.

The Commission accepts that there may be a positive relationship between marketing and the level of demand, at least some of any increase in demand, although the relationship is uncertain. It accepts that at least some of the increase in demand may occur beyond the period in which the expenditure occured. As such, the distributors are unlikely to retain the full benefit from marketing activities because demand increases in future periods will be taken into account in future demand forecasts (and so result in lower average prices rather than higher total revenues). As such, the distributors may not have an incentive to undertake an efficient level of marketing activity. This view is evidenced to some extent by the underspending on network marketing that appears to have occurred in the first regulatory period relative to the allowances made in the 1998 assumptions used to calculate reference tariffs for this current regulatory period.

Given that the strength of the relationship between marketing and demand remains unclear, and that the benefits are said to relate to long-term customer interests, the area that remains open to debate is the appropriate level of activity and expenditure.

Having carefully considered the responses to its Draft Decision, the Commission has adopted an assumption that marketing expenditure in the order of the existing levels of expenditure incurred by Multinet and Envestra will continue throughout 2003-07. As a result, it has allowed for an amount marginally over $16 million over the five-year period across the three Victorian distributors. This requires the adoption of the proposal submitted by TXU, which is to increase existing levels by $250 000 to a total of $850 000 per annum. This adjustment has been made to the base level expenditure.

In adopting this assumption, the Commission will seek to implement arrangements whereby the impacts of marketing can be objectively assessed in the Victorian context for consideration in future reviews.

---

177 2001 Electricity Distribution Price Determination, Vol. 1, p.244.

3.3.6 Costs associated with new functions and obligations

In its Draft Decision, the Commission assumed a step change of $0.5 million to reflect additional obligations in relation to what it broadly described as customer-interface obligations. This assumption had regard to the introduction of FRC, the proposed GSL payments scheme and the obligations relating to the Energy Water Ombudsman Victoria. Consistent with an approach that adopts industry benchmarks to account for the impacts of changing obligations, the Commission adopted this amount for all three distributors.

As noted earlier, there has been considerable discussion and debate about what constitutes a change in scope. As foreshadowed in earlier consultation papers, the Commission has used the term ‘changes in scope’ to refer to a change in functions from one period to the next. The Commission has distinguished ‘changes in scope’ because the cost implications of such an event would not be reflected in industry-wide productivity trends, which therefore warrants such an adjustment being made. However, the distributors have argued that the Commission should take a broader view of the matters for which specific adjustments should be made to establish expenditure forecasts. There also appears to be some uncertainty regarding the exact interpretation of the Gas Distribution System Code obligations related to metering and whether or not more stringent obligations are now being imposed.

The following sections set out the Commission’s consideration of comments made in relation to this issue as well as its assumptions relating to the above obligations. It also provides greater clarity about its own interpretation of the metering obligations included in the Gas Distribution System Code. However, the Commission notes the view expressed by distributors that there are step changes in the costs of certain inputs that must be considered irrespective of whether they relate strictly to changes in scope. These issues are discussed in more detail in section 3.3.4.

Customer interface activities (including FRC)

Each of the distributors has forecast cost increases associated with various activities relating to the interface with retailers and in some instances, end users. The reasons include increased costs due to FRC, costs relating to additional responsibilities arising from participation in the Energy Water Ombudsman Victoria (EWOV) Scheme, and the arrangements and higher levels of activity associated with fault calls and billing of multiple retailers.

In relation to the costs of introducing FRC, an important consideration noted in the Draft Decision is to ensure that costs recoverable under the Order in Council are not also included in the forecasts used to establish reference tariffs.[178] The Draft Decision set out the Commission’s interpretation of the relationship between the process of establishing operating expenditure forecasts for reference tariffs and the process of considering the recovery of FRC costs under the Order in Council, particularly the concept of ‘anticipated’ and ‘unanticipated’ costs associated with additional functions.

178 The Order in Council requires that there be no ‘double recovery’ of costs (clause 15/2, principle 4).

A number of comments made by Multinet appear to suggest a need for more clarity as to the Commission's understanding and consideration of 'anticipated' FRC costs. TXU has also requested further clarification.[179]

The Commission's approach is to allow for the cost impacts of any changes to distribution functions as part of the step change in operating expenditure from 2001. The introduction of FRC has resulted in the distributors undertaking additional functions. The Victorian Government has put in place a framework allowing for the recovery of the 'unanticipated costs' associated with these functions, which are defined as costs that do not include those costs that would have been incurred in any event. The Commission interprets this provision to refer to the incremental costs associated with the additional functions and obligations prescribed in the Order. The distinction between a new function and unanticipated costs is important.

The treatment of costs under the Order in Council process mirrors the concept of a 'step change' to expenditure as proposed and subsequently adopted by the Commission to assess expenditure forecasts for the purposes of setting reference tariffs. In other words, the calculation of the step change of costs associated with changed functions does not include the portion of costs relating to a new function that would have been incurred in any event. The Order in Council requirement to ensure that there is no double recovery of costs also means that costs that are recoverable under that Order need to be excluded from the step change calculations.

The following criteria illustrate the process of assessing whether an adjustment to the underlying operating expenditure trend should be made to allow for a new function or obligation, and the basis for calculating that adjustment:

- Is a particular obligation or function to be carried out by the distributors from 2003 to be regarded as a *new* function or obligation?
- If so, is the distributor able to recover the incremental costs associated with that new function or obligation through the FRC Order in Council process?
- If not, what is the incremental cost of undertaking this new function (that is, what are the costs over and above those that would have been incurred in any event)?

In terms of the first criterion, the Commission regards tasks such as billing and collecting revenue from a number of retailers, responding to fault calls, and managing service orders as an *existing* function or obligation. In contrast, sending an invoice to an increased number of retailers in the market is considered to be an increase in the level of activity associated with an existing function or obligation. Receiving fault calls from customers rather than retailers is a change in the way in which an existing function is carried out. However, a requirement to implement a GSL payment scheme is considered to be a new obligation.

[179] TXU, Response to Draft Decision, p.5.

In the Draft Decision, the Commission adopted an assumption ($0.5 million) to allow for the additional level of activity relating to the interface with customers and/or retailers, changes to the way in which fault calls would be received and the introduction of the GSL scheme. In doing so, it accepted that these matters would meet the second criterion noted above, in that the costs would not be recovered through the FRC Order in Council.

In response to the Draft Decision, Envestra noted that the Commission's assumed step change of $0.5 million is consistent with Envestra's initial submission related to customer service costs.[180] However, a separate submission has been made in relation to the GSL scheme that suggests that a further $100 000 to $225 000 is required.[181]

TXU submitted that the scope of billing and revenue collection has changed as a consequence of FRC and that it has revised its submission to include the following additional annual costs that are not recoverable under the FRC cost recovery process:[182]

- NRM systems/process development ($0.5 million);
- additional staff for revenue collection ($0.2 million); and
- IT production support for gas ($0.15 million).

Multinet expressed the view that the Commission's allowance for incremental costs of FRC is incorrect and unreasonable[183] and reiterated that $1.9 million additional expenditure is required to meet the requirements of FRC that are not recoverable under the Order in Council. In its Access Arrangement Information, Multinet listed these requirements as follows:

- provision of network standing data;
- network, metering and operational faults and service orders;
- distribution billing and revenue collection from multiple retailers;
- distribution customer service centre;
- distribution process associated with customer transfer; and
- IT support costs.

180 Envestra, Response to Draft Decision, p.28
181 Envestra, Presentation to the Commission on the Draft Decision, 21 August 2002, Slide 30.
182 TXU, Presentation to the Commission on the Draft Decision, 20 August 2002, Slide 18.
183 Multinet, Response to Draft Decision, p.48.

Finally, Multinet argued that using 2001 actual expenditure as a basis for establishing the future trend does not recognise the 'anticipated' costs that it will incur as a result of introducing FRC.[184] As noted above, anticipated costs are defined as the costs that would have been incurred in any event. Hence, by definition, these costs are regarded by the Order in Council as costs that should not be included in the calculation of the costs associated with additional functions to be undertaken as a result of FRC. Likewise, the Commission does not believe an adjustment to the underlying trend is warranted if the costs would have been incurred in any event because, by definition the anticipated (non-incremental) expenditure is reflected in existing expenditure levels and thus already provided for under the Commission's approach for assuming expenditure forecasts.

Having carefully considered the responses to the Draft Decision, the Commission has decided to adopt a step change of $0.5 million for customer interface activities and a separate assumption for GSL payments (as discussed below).

Finally, the Commission needs to consider costs associated with implementing FRC in Envestra's Albury network. Whilst Envestra has chosen to adopt the same FRC arrangements for Albury as it is required to for its Victorian network, it is unable to recover the costs associated with FRC through the Victorian Government's Order in Council process. As a result, Envestra has included a FRC cost recovery charge in its operating expenditure forecasts for Albury of $0.43-0.44 million per annum.

Envestra has indicated that the FRC cost recovery charge incorporated in its 2003-07 non-capital cost forecasts is based on preliminary estimates of both *capital and operating costs*.[185] It has determined this charge on the basis of the sum of the return on capital, depreciation and non-capital costs for each particular year. Envestra has proposed that in the event that FRC implementation costs exceed those forecasts, it will seek to recover those additional costs via a change in tax pass-through (see also section 4).[186]

In the Draft Decision, the Commission proposed to allow Envestra to recover the additional costs associated with FRC through a separate reference tariff component (that lies outside the main price controls). This would avoid the need to incorporate a forecast in the calculation of reference tariffs and include pass-through provisions should those forecasts prove to be less than actual costs. Accordingly, the Commission excluded forecasts of FRC costs for Albury from its Draft Decision. A separate price control will be required to permit the separate reference tariff component to recover prudent and efficient FRC incremental costs associated with Albury.

184 ibid., p.47.

185 Envestra, Information provided in response to the Commission's operating and capital expenditure request, 17 May 2002.

186 Envestra, Access Arrangement Information (Albury), 2 April 2002, p.23.

Envestra has accepted the Commission's proposed approach to FRC cost recovery for Albury, indicating that it would provide the Commission a separate tariff proposal. It also noted that 'it is anticipated that the unit costs in relation to Albury customers will be the same as those applying to regional consumers in Victoria'.[187] Details of the Commission's proposals related to this additional reference tariff component are discussed in section 3.3.

Expenditure associated with the GSL scheme

Both Multinet and TXU proposed to introduce a guaranteed service level (GSL) payments scheme for customers. In its Draft Decision, the Commission accepted the merits of introducing a GSL scheme and concluded that it should be extended to apply to Envestra's Victoria and Albury networks.

After assessing the various features of the proposed scheme, the Commission proposed certain adjustments in its Draft Decision, and made its operating expenditure estimates on the basis of the refined scheme. These assumptions reflected matters such as the size of the payments, the relevant thresholds, the proposed GSL events, definitions and payment conditions.

While Multinet and TXU both proposed the same scheme,[188] the expenditure forecasts proposed by each business differed significantly. In particular, Multinet proposed a total cost over the regulatory period of $0.65 million compared to TXU's proposed cost of $3.525 million. The differences relate to different assumptions about the likely number of events and the proportion of customers that would be expected to receive a payment in a year, as well as the estimated costs of establishing the scheme.

Prior to the Draft Decision, the Commission sought further information from both Multinet and TXU about the nature of assumptions made in relation to the number of payments to be made. The details of this information are contained in table 3.8 of the Draft Decision. In total, the two distributors proposed annual payments of $100 000 and $225 000 respectively. After carefully considering the additional information, the Commission presented its detailed forecasts in table 3.9 of the Draft Decision, which ranged from $70 000 to $85 000 and reflected the revisions proposed by the Commission.

In arriving at these estimates, the Commission relied on the gas distributors' proposals and placed particular emphasis on expected payments that were supported by reference to actual data collected by the distributors, and/or verified by the Commission through its performance monitoring information. The detailed assumptions and the basis for specific estimates of each component of the scheme were set out in the Draft Decision. Noting that the sum of these component payments constitutes less than 0.3 per cent of expenditure, the Commission chose to incorporate the projected payments in its step change assumption of $0.5 million for each distributor. The establishment costs associated with the scheme are discussed in the capital expenditure section of this Final Decision.

---

187 Envestra, Response to Draft Decision, p.17.

188 Note that the Access Arrangement Information provided by Multinet proposed a different maximum payment in relation to the failure to connect customers within 2 days of the agreed date, but this appears to have been revised in information provided to the Commission subsequently.

In response to the Draft Decision, Multinet argued that the Commission had misinterpreted the information it had provided on ‘multiple interruptions’. According to Multinet, the effect of this has been to significantly underestimate Multinet’s likely liability under the Commission’s proposed reduction in the threshold for this GSL. Envestra submitted cost estimates of between $100 000 and $225 000.

The distributors have generally expressed the view that the data related to the likely events across the different payment thresholds is not reliable. In light of the lack of reliable data and the fact that the scheme is being introduced for the first time, the Commission has decided to adopt an assumption of $200 000 for expected annual payments across the overall scheme.

New metering obligations

A number of distributors have estimated increased expenditure in relation to metering. In particular, Multinet has proposed a step change in operating expenditure from 2001 to 2003 reflecting in part, the treatment of meters as an operating expense (in contrast, TXU and Envestra have treated these costs as capital expenditure). Two factors appear to underlie the proposed increases:

- a view that the Gas Distribution System Code now requires a sampling and testing regime that is more stringent, which in turn will result in the failure of more meters and subsequently the need more replacements; and
- the age profile of the existing meters includes a significant number of meters that will, in any event, need to be replaced.

This section of the Final Decision assesses the first of these factors. The latter is discussed in relation to the future trend in overall expenditure, below.

In the Draft Decision, the Commission’s expenditure assumptions did not include the step increases attributed by the distributors to the meter testing and replacement requirements of the Gas Distribution System Code. In adopting this assumption, the Commission noted that it would consult further with the distributors prior to the Final Decision with a view to clarifying the Gas Distribution System Code requirements. This also included assessing any plans that the distributors may wish to submit in accordance with the revised provisions of the Gas Distribution System Code.

In response to the Draft Decision, Multinet raised concerns over testing requirements for the next regulatory period, stating that:

> Multinet does not support testing at 20 per cent badge rate and would not propose to include such a requirement in a testing plan. However, given that the Regulator will be in a position to approve Multinet's plan and given the Regulator’s past preference for testing at 20 per cent badge rate (as evidenced by the Regulator's change to the Gas Distribution System Code), Multinet believes that it would be prudent to plan the meter replacement program on the basis that a requirement to test at 20 per cent badge rate will be enforced.[189]

[189] Multinet, Response to Draft Decision, p.46.

Multinet indicated that the Commission's Final Decision would need to clarify the meter testing requirements for the next regulatory period, and ensure that expenditure assumptions reflected those requirements.

The Commission has carefully considered this issue and proposes to implement a transitional plan (with the Commission's approval pursuant to the Gas Distribution System Code) that will avoid excessive rates of replacement and therefore any significant impact on expenditure.

Summary of assumptions regarding changed obligations

The table below presents the Commission's conclusions in relation to the changes in obligations referred to above and the amounts adopted for this Final Decision.

TABLE 3.8
FINAL DECISION: BASE LEVEL OPERATING EXPENDITURE ADJUSTED FOR CHANGES IN OBLIGATIONS

Obligations	Envestra – Albury	Envestra – Victoria	Multinet	TXU
BASE LEVEL 2002 (From table 3.11)				
Customer Interface (Incl FRC)	$0.5 million			
GSL Scheme	$0.2 million			
Metering	Nil – transitional plan			
BASE LEVEL 2002 (Ajusted for change in obligations)	t			

3.3.7 Operating expenditure trend

Having taken into account any step changes in the scope of distribution activities since 2001, the Commission needs to establish assumptions about the trend in future expenditure levels.

In its Draft Decision, the Commission expressed the view that the assumption that it adopts in relation to the operating expenditure trend needs to reflect the reasonable gains that an efficient service provider would be expected to achieve and the net movement in industry-wide factors that impact on expenditure levels. In its Draft Decision, the Commission assumed an annual reduction in operating expenditure of one per cent per annum, which it considered to be conservative in light of studies by other regulators and the trend implied by the distributors' proposals.

Each of the distributors has argued that there are a number of factors impacting on future costs that are likely to result in an increasing operating expenditure trend from 2003, and that the Commission's assumptions imply productivity gains that are too onerous. Accordingly, this section provides an overview of the Commission's assumptions in the Draft Decision and the reasons for adopting those assumptions. It then considers the issues raised in response to the Draft Decision, and presents its final conclusions with respect to the operating expenditure trend assumed for this Final Decision.

Draft Decision

In forming its view on the appropriate operating expenditure trend, the Commission had regard to the extensive analysis presented in recent decisions by two other Australian regulators of gas distributors, namely the Queensland Competition Authority (QCA) and the Independent Pricing and Regulatory Tribunal (IPART).[190] The Commission has also had regard to the trend implied by the total annual expenditure submitted by the distributors as a whole.

QCA indicated that its assumed trend in network operating expenditure comprised an adjustment to phase-out the relevant distributor's level of inefficiency at the commencement of the regulatory period,[191] and an adjustment to take account of expected productivity gains in network operating and maintenance expenditure over the regulatory period. Given that the Commission considers that it is reasonable to infer that the distributors are efficient at the end of the first access arrangement period (as a result of their commercial incentives to minimise cost), the Commission considered only the second of these elements to be relevant. Excluding inflation, the trend assumed by the QCA was expressed as:

> Network Opex = Base Network Opex x (1 – X + 0.8 x G)
>
> where X was assumed to be 2.5 per cent, G is forecast growth in volumes, and the '0.8' can be interpreted as the elasticity of network operating and maintenance expenditure to growth.

It also assumed that administration and marketing expenditure would remain constant in nominal terms, which implied a real reduction in of this portion of expenditure of approximately 2.5 per cent per annum.[192]

The approach adopted by IPART was similar to that adopted by the QCA.[193] As with QCA, IPART formed a view on the efficiency of AGL's operating expenditure at the commencement of the regulatory period, and assumed cost reductions for some components of expenditure in addition to that implied by its assumption about industry-wide productivity improvements.[194] Again, the Commission only considered IPART's assumptions about the ongoing trend in expenditure.

---

190 Op. cit., QCA Final Decision, pp.260-261, IPART Final Decision (AGL), July 2000, pp.131-138.

191 Allgas was found already to be efficient, and so no additional adjustment was included. Envestra's network operating and maintenance cost benchmarks were phased down by an additional 0.85 per cent per annum on account of its inefficiency at the commencement of the regulatory period.

192 Op. cit., QCA Final Decision, pp.261-262.

193 Independent Pricing and Regulatory Tribunal, Final Decision, pp.136-137.

194 ibid., p.133. Marketing expenditure was assumed to fall by 57 per cent over the period.

IPART assumed an annual real cost reduction of 3 per cent per annum for controllable operating expenditure, and adjusted this to take account of the impact of growth on expenditure. Growth was measured as the average of the rate of growth in customer numbers and the rate of growth in throughput.

The approximate implications of applying the approaches used by the QCA and IPART[195] can be calculated by using the inputs relating to the Victorian distributors. The results are shown in the table below, together with the trend implied by the distributors' forecasts.

TABLE 3.9
DRAFT DEICISON: TRENDS IN OPERATING EXPENDITURE

	QCA	IPART	Implied by DB Proposals	Draft Decision
Envestra – Albury	1.8%	1.7%	0.0%	**1.0%**
Envestra – Victoria	1.6%	1.3%	-0.3%	**1.0%**
Multinet	1.8%	1.7%	1.8%	**1.0%**
TXU	1.2%	0.4%	1.3%	**1.0%**
Average	1.6%	1.3%	1.0%	**1.0%**

Note: A positive figure for the trend implies a real reduction in the operating expenditure benchmark.

While the Commission noted that there was some variation between the assumptions across the distributors, the distributors' implied productivity trend (proposed gains) considered across all businesses was at the lower end of the trend implied by the QCA and IPART approaches.

In calculating the trends implied by the QCA and IPART studies, the Commission notes that both included measures relating to the relative efficiency of each regulated entity's existing costs as well as industry-wide productivity improvements. As the Commission has considered it reasonable to infer that the distributors are efficient (as a result of their commercial incentives to minimise cost) it was careful to have regard only to that part of the findings that related to industry-wide productivity improvements.

One of the issues noted in the Draft Decision was the need to account for growth and the different approaches that were used by QCA and IPART. QCA's approach incorporates a factor (0.8) to capture the assumed sensitivity of operating expenditure to growth, whereas IPART's approach assumes a one-for-one relationship between operating expenditure and growth.

195 Note that the implications of adopting the IPART approach have been calculated using projected customer numbers alone as the measure of growth The growth in customer numbers projected for the next period exceeds the growth in throughput, and so the trend shown in the table would understate the annual assumed cost reductions implied by IPART's approach.

The Commission considered that the assumptions about the strength of the relationship between operating cost and growth may be overstated. Generally, it considered that economies of scale would result in the ratio of inputs to outputs declining as customer numbers expanded. This appears to be supported by the view expressed by a number of Victorian distributors that operating costs increase at a rate of $11 per new customer.

An implication may be that the trend reduction implied for high-growth distributors would be understated, whereas the trend reduction implied for low-growth distributors would be overstated. Accordingly, the Commission considered it appropriate to have regard to the *average* of the trend across the distributors that would be implied by the QCA and IPART approaches.

Responses to Draft Decision

In response to the Draft Decision, the distributors expressed the view the Commission's productivity assumptions were too onerous, and that the Commission needed to account for specific items for which costs are expected to increase. Each of the distributors expressed the view that adjustments were needed to incorporate increased insurance premiums.

In terms of the productivity assumptions, both Multinet and Envestra expressed the view that the Commission's productivity assumptions were both aggressive and unrealistic. Multinet, for example, claimed that expenditure benchmarks for the current period have been difficult to achieve and further:

> Given the significant efficiency gains that were incorporated into those (current access period) benchmarks, and Multinet's performance relative to those benchmarks, the company is firmly of the view that the scope for further productivity improvements over the Second access arrangement period is very limited. In view of this, and on the assumption that the Regulator's Final Decision takes full account of the additional costs associated with the scope changes … Multinet considers that the assumed rate of productivity improvement in non-capital costs over the Second Access Arrangement Period cannot reasonably be expected to exceed 1 per cent per annum.[196]

Similarly, Envestra expressed concerns over its ability to achieve the Commission's assumed productivity trend, arguing that it would not be able to continue to achieve the levels of efficiency attained in the current access period, and stating that:

> Envestra makes every effort to ensure that operating costs are minimised. Taking these factors into account Envestra has internal operating cost targets to cap annual cost increases to CPI minus 0.5 per cent. This will prove increasingly difficult to achieve as the number of network connections grows and the size of the network to be maintained increases.[197]

196 Multinet, Response to Draft Decision, p.42.
197 Envestra, Response to Draft Decision, p.30.

Envestra proposed that a growth allowance of $11 per customer be incorporated into the Commission's productivity assumptions[198] and calculated the reduction in the cost per connection implied by the Draft Decision to be in the order of 3 per cent per annum.[199]

Envestra also appeared to question whether the Commission had allowed for the effects of volume growth in the use of estimates of productivity trends:

> It is usual for productivity measures to be presented in terms of a cost per unit of output. It is surprising that the Commission has not adopted this approach and assumes that productivity will be achieved at the total cost level which implicitly assumes that operating costs per unit (customer or kilometre of main) will fall at a greater rate.[200]

TXU and Multinet also argued against the Commission's assumption that there would be a declining trend in operating expenditure, arguing that:

> Given the Commission's assumption that the industry is already efficient and given the pace of technological change in the gas distribution sector, it is difficult to conceive how it could be assumed that efficiency improvements in this sector of the economy could be greater than those of the entire economy. Indeed, because productivity growth in the gas distribution sector is likely to be lower than that of the economy generally (and the economy wide productivity improvements are already captured in the CPI generally), then the assumed productivity growth should be at least zero and could be more than zero (ie. 'X' in the true CPI-X formula would be negative).
>
> The Commission cites evidence from a number of other regulators to support its case in regard to the forecast productivity improvements but these regulators are not adopting the same primary assumption regarding the efficiency of the businesses. They are therefore re-establishing the level of efficient costs of each business and providing a mechanism for them to achieve that target over a price control period. This is not what the Commission is proposing to do.[201]

TXU emphasised the need to account for the projected increases in certain input costs that the Commission had not considered as being entirely related to additional functions. The distributors identified the following matters:

- insurance premiums
- the cyclical nature of metering costs;
- superannuation;
- regulatory reviews; and
- self-insurance and hedging.

198 ibid, p.26.
199 ibid, p.30.
200 Envestra, Response to Draft Decision, p.30.
201 TXU, Response to the Draft Decision, Attachment D, pp.24-25; Multinet, Response to the Draft Decision, Attachment C, p.23.

The Commission notes that the distributors have included in their operating expenditure forecasts allowances for *self-insurance*, and in the case of Multinet, a $1.6 million allowance representing the 'fair value' of *hedging* to VENCorp's revised effective degree days standard. Both of these issues are discussed in section 3.6.

Further detail of the comments made in relation to these matters is provided below, together with the Commission's further analysis and final assumptions.

Each distributor raised the issue of increases in *insurance premiums*. TXU provided an estimate of expenditure on insurance premiums of $0.674 million per annum – an increase of 80.1 per cent over the current access arrangement period. Envestra also claimed that insurance premiums, which have been unsustainably low until recently, have increased by $0.7 million since 2001. In particular, it commented that:

> While Envestra accepts the general rationale that some operating cost items will increase and others will decrease and, that in the majority of cases, these will be picked up in the productivity trend, this is clearly unreasonable in this instance.
>
> The insurance industry is clearly in the process of restructuring its product offerings and associated premiums and it is likely that there will be some long term and permanent changes in both areas. There appears to be little in the way of respite from premium increases and decreases in risk coverage by insurers over the short to medium term, ie. it is highly likely that premiums will remain at levels similar to or higher than those estimated by Envestra for the 2003 to 2007 period.[202]

Both Multinet and TXU highlighted the *cyclical nature of metering* programs, including meter replacement programs. In particular, Multinet commented that:

> These (meter replacement) estimates are materially higher than the cost actually incurred in relation to this activity in 2000. (In addition, it is noted that the estimated costs exhibit a material degree of variability from one year to the next, reflecting the age profile of the assets. It is noted that the Regulator's broad-brush assumption that non-capital costs can be estimated by applying 'trend estimates' does not adequately account for these legitimate variations in efficient costs).[203]

Similarly, Envestra noted the cyclical nature of costs associated with five-yearly regulatory reviews and proposed that an allowance of $0.5 million be incorporated into the assumptions for the Final Decision.

Envestra also submitted that its 2001 reported expenditure did not reflect the cessation of a 'superannuation holiday', stating this will require an additional $0.6 million (2003 dollars) in superannuation contributions by Origin Energy Asset Management on behalf of its members. Further, an increase in the superannuation levy from 6 per cent to 9 per cent in 2002-03 will lead to an annual cost increase of $0.75 million. Similarly, Multinet advised the Commission that certain contracts were due to expire post-2001 and that the reported expenditure will not reflect the future payments to external providers.[204]

With respect to these costs, Envestra has argued that:

---

202 Envestra, Response to Draft Decision, p.28.
203 Multinet, Response to Draft Decision, p.45.
204 Multinet, Response to Draft Decision, p.41.

> The Commission is proposing that these cost increases continue to be absorbed by Envestra, implying that it is part of the productivity trend assumed by the Commission. It is inappropriate that changes in superannuation costs be treated like another expenditure line item. The changes in superannuation costs are more akin to a change in tax over which Envestra has no control. It is therefore unreasonable for the Commission to disallow these costs in the 2003 forecasts.[205]

Both Envestra and Multinet also raised the issue of cost increases associated with external service providers. In particular, Envestra claimed that:

> GasNet will be downgrading the transmission pipeline supplying Envestra's network in 2005. Operating costs will therefore be increased from this point onwards. These higher charges clearly represent a scope change over which Envestra has no control and must be included in the forecasts from 2005 onwards.[206]

Finally, Multinet expressed the view that the Commission should adopt a stand alone forecast for each year of the 2003-07 period, rather than establish a base figure and apply a trend for the remaining years.

Further analysis

Section 3.3.3 of this Final Decision sets out the Commission's assessment of the responses received in relation to its overall approach to assessing the distributors' proposals and its conclusions about the approach to be used in this Final Decision. A key consideration for the Commission is the Gas Code requirement that the operating expenditure benchmarks used to derive reference tariffs must reflect best estimates arrived at on a reasonable basis. Accordingly, the Commission has sought to avoid adopting estimates that rely too heavily on items that the distributors consider have rising costs, without having appropriate regard to other (unidentified) items that may have declining costs. At the same time, the Commission wants to ensure that it does not adopt assumptions inadvertently that do not adequately reflect the overall expenditure requirements that a prudent service provider would face during the next regulatory period.

The Commission does not accept Envestra's argument that it has not accounted for growth in applying estimates of productivity growth. As noted above, the formulae employed to imply an expenditure trend from estimates of productivity growth explicitly allow for the impact on volume growth. The Commission also has not included Envestra's proposal to add $11 per customer to its operating expenditure for a similar reason – that is, because the externally estimated productivity trend already includes an adjustment to take account of the effect of volume growth on costs.

---

205 Envestra, Response to Draft Decision, 9 August 2002, p.28.
206 ibid, p.28.

In addition, the Commission does not accept TXU and Multinet's suggestion that it is 'difficult to conceive how it could be assumed that efficiency improvements in this sector of the economy could be greater than those of the entire economy' and that 'productivity growth in the gas distribution sector is likely to be lower than that of the economy generally'. TXU and Multinet did not provide any empirical evidence to support these statements. Further, the empirical evidence relied upon by the Commission does not support TXU and Multinet's argument about the rate of productivity growth in gas distribution.

The Commission also does not accept TXU and Multinet's argument that, by drawing on the assumptions adopted by other regulators, the Commission has included a component in its trend that the other regulators had intended to reflect the inefficiency of the relevant regulated entity. As discussed above, the Commission has carefully drawn on other regulators' assumptions about the ongoing productivity gains expected from an efficient firm only, and has not considered any other 'inefficiency' element in the trend assumptions that those regulators may have adopted.

Accordingly, on the one hand, the Commission has had regard to industry-wide productivity studies and other material that suggest that it would not be unreasonable to expect that a prudent service provider would achieve savings of 1 per cent (in real terms) over time. On the other hand, the distributors have provided the Commission with a selection of items, some of which, when examined individually, would appear to warrant upward adjustment to the forecasts used to establish reference tariffs. This appears to be the case for insurance premiums.

The Commission considers that, in practical business terms, the increases in cost items identified by the distributors would generally be regarded as part of the normal operating environment of providing services, with some costs increasing and others decreasing. Accordingly, the Commission considers that a prudent service provider would be expected to manage the 'swings and roundabouts' in its operating costs while maintaining a trend of productivity improvement. In other words, the Commission considers that this is a reasonable characterisation of what would occur in a competitive market. There would be inevitable changes in priorities, activity levels and day-to-day issues that need to be managed from one year to the next by adjusting priorities and re-allocating resources.

In any event, the Commission would expect that there are items not identified by distributors that were incurred in 2001 as a 'once-off' and others that could be expected to reduce over the next period. To some extent this is supported by the fact that some distributors estimated increases in certain cost items whereas others have not and vice-versa.

Trend assumed for Final Decision

The Commission has decided to adopt a separate assumption for the change in costs from 2001 to 2003 that are estimated to have occurred as a result of industry-wide changes in input costs. In adopting this approach, the Commission has sought to avoid a process of approving line-by-line cost projections and notes the requirement that reference tariffs seek to replicate the outcomes of a competitive market. On balance, the Commission accepts that there have been changes to insurance costs on an industry-wide basis.

For the purposes of this Final Decision, the Commission has assumed that the trend in expenditure over the past twelve months has increased due to rising insurance premiums. The operating expenditure assumptions incorporate a 'benchmark' of $800 000 for that particular year, which takes into account growth in customer numbers and productivity gains. The Commission considers that this is a reasonable benchmark and recognises that the actual costs that may have been incurred by each distributor will vary according to firm-specific arrangements. As noted during the consultation process, the Commission believes that adopting an industry benchmark is preferable to assessing firm-specific costs.

In terms of the ongoing trend, the Commission notes Multinet's view that the Commission should examine the forecasts for each year on a separate basis. However, the Commission considers such an approach implies a degree of precision with respect to the overall forecast that would not be achieved without a detailed examination of all cost items over time. For the reasons provided earlier, the Commission has adopted an approach that avoids such a detailed examination and considers that the Draft Decision assumption that costs will reduce in real terms by 1 per cent per annum is also appropriate for this Final Decision in light of the external estimates of productivity growth used by other regulators (as summarised in the Draft Decision) and the distributors' initial proposals.

3.3.8 Assumptions adopted for Final Decision

The assumptions adopted by the Commission with respect to each of the items discussed above are summarised in the table below.

TABLE 3.10

FINAL DECISION: SUMMARY OF OPERATING EXPENDITURE ASSUMPTIONS

	Assumptions
BASE LEVEL	
Reported 2001 Expenditure	Exclusion of finance transaction costs from operating expenditure to cost of capital (Envestra)
	Addition to correct for change in capitalisation policy (Envestra)
	Addition to correct initial licence fee adjustment (All)
Marketing	Existing levels (with increase for TXU) maintained.
Licence Fees	To be recovered through new price control arrangements – error in 2001 assumptions adjusted
NEW OBLIGATIONS	
Customer Issues (Inc. FRC)	An amount included to reflect additional customer-related activities new obligations and implementation costs
GSL Scheme	An amount to be included to reflect new obligations and implementation costs
Metering	No change reflecting the adoption of transition strategy
FUTURE TRENDS	
Productivity	Retain 1 percent for 2004-07
Metering, Regulatory Reviews, Superannuation, Insurance Premiums	Apply separate amount for 2002-03 reflecting industry-wide increase in insurance premiums. Other input changes reflected in overall trend
Self-insurance, hedging, amortisation of financing costs	These matters are considered in section 3.6. Allowances have not been included in the operating expenditure assumptions for the reasons provided in Appendix C.

Errata: A row relating to OEAM (Envestra) was incorrectly contained in this table in version prior to 10 October 2002.

The specific amounts included in the Commission's assumptions for this Final Decision with respect to operating expenditure are set out in table 3.11.

TABLE 3.11
FINAL DECISION: BASE LEVEL OPERATING EXPENDITURE ASSUMPTIONS ($ million in July 2001 prices)

	Envestra Albury	Envestra Victoria	Multinet	TXU
REPORTED 2001 COSTS (a)	1.2	37.2	37.4	38.4
Licence fee error		0.35	0.35	0.35
Capitalisation	0.05	1.50		
Finance cost amortisation		(3.90)		
Marketing (b)				0.26
BASE LEVEL 2001	**1.20**	**35.2**	**37.8**	**39.0**
Trend from 2001 to 2002 (c)	0.04	0.3	-0.0	-0.1
BASE LEVEL 2002	1.16	34.8	37.8	39.0
Step change for obligations		0.7	0.7	0.7
Trend from 2002 to 2003		0.8	0.8	0.8
BASE LEVEL 2003	1.19	36.3	39.3	40.5
Correction factors (d)		0.7	5.7	2.8
Trend from 2003-07	1.0%	1.0%	1.0%	1.0%
EXPENDITURE 2003-07	Refer table 3.12			

(a) As adopted in the Draft Decision

(b) Refer to marketing assumptions in section 3.3.3.

(c) The reduction assumed in the calculation of existing reference tariffs between 2001 and 2002.

(d) Correction factors are amounts to be allowed pursuant to the existing price controls. They correct for changes to the forecasts used in the annual tariff approval process.

TABLE 3.12
FINAL DECISION: OPERATING EXPENDITURE ASSUMPTIONS 2003-07 ($ million in July 2001 prices)

	2003	2004	2005	2006	2007
Envestra Albury	1.2	1.2	1.2	1.2	1.1
Envestra Victoria	37.0	35.9	35.6	35.2	34.9
Multinet	44.9	38.9	38.5	38.1	37.7
TXU	43.4	40.1	39.7	39.3	38.9

3.4 Capital expenditure

3.4.1 Introduction

Under section 8.20, reference tariffs may be determined on the basis of capital expenditure[207] that is forecast to occur within the access arrangement period, provided that it is reasonably expected to pass the requirements of section 8.16 when it is forecast to occur. Section 8.16 requires the Commission to ensure that the distributors' capital expenditure forecasts:

- do not exceed the amount that would be invested by a prudent service provider acting efficiently, in accordance with accepted good industry practice, and to achieve the lowest sustainable cost of delivering services; and
- satisfy one of three tests namely: anticipated incremental revenue exceeds the expected cost; the expenditure has system wide benefits; or the expenditure is necessary to maintain the safety and integrity of the network.

Section 8.2 lists the factors about which the Commission must be satisfied to approve reference tariffs, including that any forecasts required to set reference tariffs (for instance, forecasts of capital expenditure) must represent 'best estimates arrived at on a reasonable basis'. In assessing compliance with the requirements of section 8 of the Code, section 8.49 states that the regulator may determine its own policies, subject to the requirement for public consultation.

In consultation prior to the distributors' submitting their proposed Revisions, the Commission outlined its proposed approach to assessing capital expenditure forecasts.[208] In summary, the Commission asked the distributors to include in their proposed Revisions (and accompanying Access Arrangement Information):

- actual capital expenditure results for 1998-2001, and an estimate of capital expenditure for 2002;
- capital expenditure forecasts for the 2003-07 regulatory period, together with any supporting information that they considered to be appropriate, including an explanation of any relevant factors underpinning their forecasts;
- the assumptions that they have made about expenditure associated with projects to extend supply to currently unreticulated towns; and
- the assumptions that they have made about the different dimensions of output over the regulatory period, and the assumptions about the relationship between output and expenditure for infill projects, the organic extension of the network and connection of customers in these areas.

---

207 The Gas Code uses the term new facilities investment to refer to capital expenditure. These terms are used interchangeably in this report.

208 Op. cit., Position Paper, pp.53-54; Further Guidance to Gas Distributors, pp.44-46.

This section sets out the details associated with the Commission's assumptions adopted in relation to forecast capital expenditure. It provides an overview of the distributors' proposals, the assumptions adopted by the Commission in its Draft Decision and the comments received in response to the Draft Decision. It also discusses the specific conclusions with respect to the following categories of capital expenditure:

- renewal of low pressure mains;
- growth-related expenditure, both customer-initiated and network augmentation;
- meter related capital expenditure; and
- other capital expenditure.

3.4.2 Distributors' proposed forecasts

The table below sets out the distributors' initial forecast capital expenditure for the 2003-07 access arrangement period. The Commission notes that the distributors have adjusted their capital expenditure forecasts on a number of occasions throughout its consultation process. These are identified in the relevant sections related to each category of capital expenditure.

TABLE 3.13
DISTRIBUTORS' PROPOSED CAPITAL EXPENDITURE FORECASTS, 2003-07 ($ million in July 2001 prices)

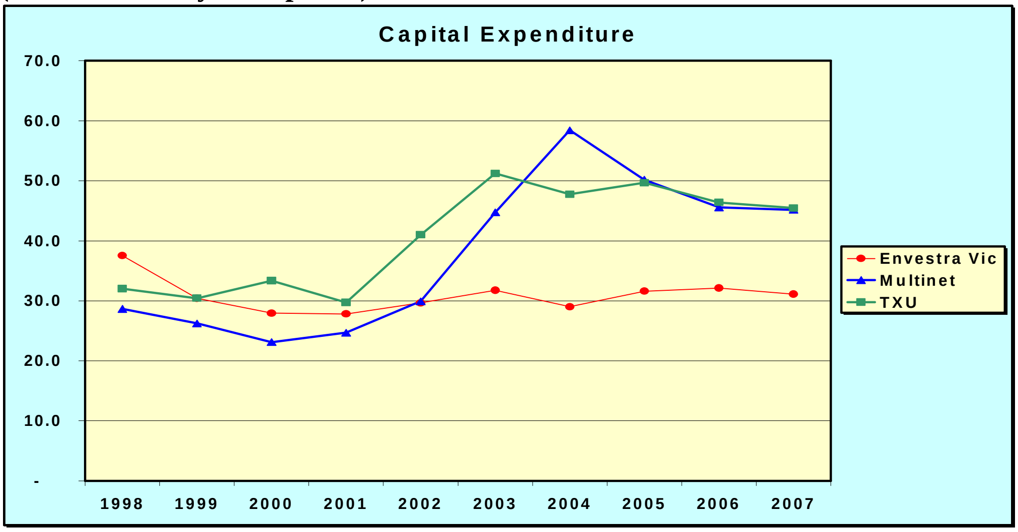
	Average 1998 – 2002	2003	2004	2005	2006	2007	Total 2003-07
Envestra – Albury	*0.8*	0.6	0.7	0.9	0.8	0.8	**3.8**
Envestra – Victoria	*28.3*	31.8	29.0	31.6	32.1	31.1	**155.7**
Multinet	*24.3*	44.7	58.4	50.2	45.6	45.2	**244.1**
TXU	*29.7*	51.2	47.8	49.7	46.4	45.4	**240.5**

Capital expenditure figures for both Envestra Victoria and Albury have been adjusted to reflect constant prices as at July 2001. Envestra's forecast for 2003 includes $5.7 million related to FRC.

Both Multinet and TXU have forecast significant increases in capital expenditure from the current levels. The magnitude of the forecast increases is depicted in the chart below, which shows the actual gross expenditure for each gas distribution *network* since 1997 together with the forecasts for 2003-07.

FIGURE 3.14

DISTRIBUTORS' ACTUAL AND FORECAST CAPITAL EXPENDITURE
($ million in July 2001 prices)



The reasons put forward by Multinet and TXU for the significant increases relate predominantly to the need to replace more of their existing low-pressure networks than has occurred in recent years, and in the case of Multinet, to undertake certain growth-related projects in addition to customer-initiated capital expenditure. The proposals put forward by Envestra Victoria reflect in part a more reactive approach to asset replacements rather than an accelerated program. The basis for the capital works proposed by the distributors is discussed in more detail in the following sections.

The Commission has accepted that Envestra's forecasts for its Albury business represent best estimates arrived at a reasonable basis, and meet the other relevant requirements of the Gas Code, and so have been accepted by the Commission. Accordingly, the discussion below is restricted to Envestra Victoria, TXU and Multinet.

3.4.3 Draft Decision

The Commission noted in its Draft Decision that increases of the magnitude proposed by TXU and Multinet would need to be supported clearly by evidence of the need for such an expansive program of works relative to existing levels. Having considered the information provided prior to releasing the Draft Decision, the Commission concluded that it was yet to be satisfied that the capital expenditure forecasts proposed by TXU and Multinet could be regarded as the best estimates arrived at on a reasonable basis, or that the expenditure would be undertaken by a 'prudent service provider acting efficiently in accordance with good and accepted industry practice'.

For the purposes of the Draft Decision, the Commission adopted assumptions for all three distributors that were based on existing levels of capital expenditure, with a 20 per cent increase to reflect additional forecast expenditure in relation to new connections and the implementation of the GSL payments scheme. This level of capital expenditure was consistent with Envestra's proposals.

In adopting these assumptions, the Commission noted the view expressed by the distributors that previous levels of capital expenditure had been prudent and efficient; that most capital expenditure is driven by mandatory safety and other regulatory requirements; and that responsible asset management should not lead to ‘bow waves’ in renewals expenditure. The Commission also stated that:

> In adopting these assumptions, the Commission notes that it has foreshadowed the need to consult further with the Office of Gas Safety in relation to the finalisation of asset management plans. It also notes that the distributors are open to providing the Commission with further information substantiating their proposed expenditure in response to this Draft Decision.[209]

This reflects the fact that the plans submitted by Multinet and TXU to the Office of Gas Safety (OGS) were in draft form and still being considered by OGS. Further consultation has occurred since the Draft Decision, the outcomes of which are discussed in section 3.4.5. Before turning to the outcomes of that process, an overview of the responses received in relation to the Draft Decision is provided below.

3.4.4 Responses to the Draft Decision

In response to the Draft Decision, both Multinet and TXU emphasised the need for the Commission to adopt capital expenditure assumptions that reflect the importance of completing the works identified in their respective proposals. Envestra, with proposals that reflect existing levels, argued that the Commission had not provided an allowance for implementing the proposed GSL scheme as well as the growth in customer numbers assumed by the Commission. Following further consultation with OGS, Envestra has made some adjustments to its existing proposals.

The Customer Energy Coalition was highly critical of the Commission for assuming that capital expenditure would increase from existing levels, without undertaking a more detailed examination.[210] It also pointed to the experience of regulators in the United Kingdom, whereby prices were set with reference to forecast increases in capital expenditure that did not eventuate.

Both Multinet and TXU questioned the extent to which the Commission should place weight on recent capital expenditure levels in forecasting future requirements. For example, TXU noted that:

> Conditions in the network today are not the same as 5 years ago. Low pressure cast iron pipes in the most densely populated areas of the network are becoming old and are deteriorating. Meters installed 15-20 years ago during a period where large numbers of gas connections occurred need replacing over the next 5 years.[211]

Similarly, Multinet expressed the view that:

[209] Draft Decision, p.85.
[210] Customer Energy Coalition, Response to Draft Decision, 23 August 2002, pp.43-44.
[211] TXU, Response to Draft Decision, Attachment A, p.22.

> This approach is reasonably valid for certain classes of capital (such as customer initiated capital, for instance) that have a relatively consistent underlying trend and if the average is taken over an appropriate period.
>
> However, areas in which the Regulator's approach is less appropriate are demand-related (reinforcement) capital expenditure and renewals capital expenditure.
>
> Multinet considers that in the case of these two categories, application of the Regulator's proposed approach results in the risk of substantially under-estimating efficient levels of capital expenditure for the Second Access Arrangement Period.[212]

In contrast, the Customer Energy Coalition presented details of the forecasts submitted to (and subsequently used by) UK regulators, and contrasted them with the actual outcomes. In doing so, it expressed concerns about the strategic opportunities that exist for distributors to overstate future expenditure requirements at the time prices are set, and then underspend after the event:

> CAPEX has a significant impact on future revenues and asset values due to the scope for exercise of 'strategic' behaviour in [the distributors] forecasts. … The distributors' forecasts of CAPEX are very obviously excessively conservative. In fact the forecasts appear to be influenced by 'strategic behaviour' to a point that threatens the industry's credibility.[213]

However, both Multinet and TXU stressed the need for their respective works programs in terms of ensuring the ongoing safety and reliability of their gas networks. For instance, TXU commented that:

> [it] has now reached a point where, unless renewals are increased in the next regulatory period, safety could become an issue. This moves the renewal expenditure into non-discretionary territory.[214]

3.4.5 Summary of overall approach and conclusions

The Commission has adopted a two-stage approach in this Final Decision. In the first instance, it has directed its assessment of the distributors' capital expenditure forecasts to the nature and scope of the capital works proposed. After forming its views about the nature and scope of the works to be undertaken, the Commission has assessed the distributors' forecast capital expenditure implied by those works. In turn, it has assessed forecast capital expenditure against the distributors' estimated direct costs for each capital expenditure category, and considered the overhead component separately.

---

[212] Multinet, Response to Draft Decision, pp.52-53.

[213] Customer Energy Coalition, Response to Draft Decision, prepared by Pareto Associates, August 2002, p.12 and p.43.

[214] TXU, Response to Draft Decision, 7 August 2002, Attachment A, pp.3-5.

Replacements

The Commission is mindful of the importance placed on safety and reliability, both in terms of the formal provisions of the Gas Code and the Gas Safety Act, and more generally in terms of the interests of users and the distributors. For example, section 2.24 of the Gas Code states that the Commission must take into account 'the operational and technical requirements necessary for the safe and reliable operation of the Covered Pipeline'. Section 8.1 requires that reference tariffs be designed to achieve, amongst other things, the objective of 'ensuring the safe and reliable operation of the pipeline.'

In reaching its conclusions about the appropriate assumptions to make with respect to the extent of asset replacements over the 2003-07 access arrangement period, the Commission has placed considerable weight on safety and reliability considerations and the views of OGS. It has decided to adopt the replacement works proposed by the distributors as the basis for estimating capital expenditure for the 2003-07 access arrangement period. In the case of Multinet and TXU, this represents a significant proportion of their existing low-pressure networks that currently exists and forms part of a replacement strategy designed to improve safety and reliability over the longer-term.

The Commission is mindful of the problems referred to by the Customer Energy Coalition, particularly the incentive for regulated entities to overstate expenditure requirements prior to setting future price caps and then underspend after the event. It is also conscious of the general information disadvantage that the Commission faces relative to the distributors. While the Commission does not believe that a detailed project-by-project assessment will necessarily overcome these problems, it recognises that certain arrangements need to be put in place with a view to ensuring that these works are undertaken. There is a strong rationale for introducing such as arrangement given the importance of the long-term safety and reliability of the gas distribution networks and the fact that the reference tariffs applying to users have been calculated to recover the costs associated with those significant works.

In light of these considerations, the Commission intends to work with OGS to develop appropriate monitoring and reporting arrangements in relation to the distributors' capital replacement programs. In particular, it will look to the OGS to carry out regular reviews of each distributor's replacement program under its charter for gas safety and reliability. Consistent with this approach, the Commission would expect the distributors to work with OGS to develop asset management plans and their predictive modelling tools, to ensure that priority is given to areas that have the most significant impact on safety and reliability.

In the event that less capital expenditure is undertaken over the 2003-07 access arrangement period than the forecast assumed by the Commission in setting these reference tariffs, the Commission will need to be satisfied that this has not occurred as a result of an imprudent and uneconomic deferral of necessary works. In the event that it is not satisfied that this is the case, it will not consider the reduction in expenditure (calculated at benchmark rates) arising from the imprudent deferral to reflect an efficiency gain. Deferring expenditure in this way contrasts with the situation whereby an approximate number of kilometres of mains are replaced at a total cost that turns out to be less than anticipated. This is broadly consistent with the proposed adjustment to the carryover for growth, whereby an adjustment has been foreshadowed to the measurement of efficiency to account for the benchmark costs of meeting growth that turns out to be different to that which was forecast in calculating reference tariffs.

The Commission has accepted significant increases in Multinet and TXU's capital programs on the grounds of safety and reliability. However, it will take appropriate regulatory action during the 2003-07 access arrangement period to monitor the delivery of these programs and to ensure that customers are not disadvantaged by undeperformance.

Growth and other capital expenditure

The projected number of customer connections and the need for network augmentation largely drives the nature and extent of the capital works required in relation to growth. In terms of customer connections, the Commission has adopted the same numbers as those used to establish forecast demand for each distributor to assess the distributors' growth-related capital expenditure (see section 3.9). In terms of augmentation, Envestra and TXU's proposed works are relatively modest ($7-9 million) compared to the works proposed by Multinet ($25 million). The Commission has accepted the works proposed by the distributors. Details of the Commission's consideration of capital expenditure for growth are provided in section 3.4.7.

In terms of the projected number of meter replacements, the Commission proposes to continue with the current arrangement related to the retention of meters in the field after the initial life. These meters will continue to be accepted for extending the retention in the field under the existing criterion (100 per cent of the badge capacity of the meter) in the current sampling plan approved by the Commission. This is a transitional arrangement that will apply until the costs and benefits of introducing a more stringent testing regime can be assessed fully. Finally, each distributor has identified certain initiatives categorised as 'other' capital expenditure. Both TXU and Envestra have similar overall expenditure, which the Commission has accepted for this Final Decision. However, for Multinet, the Commission has accepted network-related expenditure and forecasts of IT expenditure that are in the same order of magnitude as Envestra and TXU. Details are provided in section 3.4.9.

Unit costs of capital expenditure

Having reached its conclusions about the nature and scope of works projected for the 2003-07 access arrangement period, the Commission has considered the nature of the appropriate estimates required to undertake these works, in accordance with the requirements of the Gas Code.

As far as practicable, the Commission has sought to rely on benchmark comparisons of direct unit costs in terms of capital expenditure per metre of mains replacement, expenditure per customer connected and average costs of meter replacement and installation. It has sought to compare the distributors' respective forecasts with those of other comparable firms as well as against recent trends. It has also discussed in detail its views as to why using benchmark assumptions best meets the requirements of the Gas Code in relation to operating expenditure (see section 3.3). Those views apply equally to capital expenditure.

The Commission has concluded that the underlying unit costs estimated by the distributors are in some instances higher than those that the Commission believes represent the best estimates arrived at on a reasonable basis of the costs that would be incurred by a prudent and efficient service provider. The variation appears to be due partly to the overheads that each distributor estimates it will incur in undertaking their respective capital works programs. The estimated overhead component of the distributors' forecasts of total capital expenditure varies between distributors by virtue of them applying different percentage rates. The Commission believes instead that overheads will not increase in direct proportion to capital expenditure and has adopted a benchmark assumption based on an increase in the reported overheads for 2001. This is discussed in section 3.4.6.

The conclusions reached by the Commission for this Final Decision are presented in the table below.

TABLE 3.15
FINAL DECISION: CAPITAL EXPENDITURE FORECASTS 2003-07
($ million in July 2001 prices)

	2001 Actual	2003	2004	2005	2006	2007	Total 2003-07
Envestra Albury	$0.89	$0.76	$0.76	$0.76	$0.76	$0.76	**$3.8**
Envestra Victoria	$28.4	$28.3	$28.3	$28.3	$28.3	$28.3	**$141.7**
Multinet	$24.7	$41.5	$41.5	$41.5	$41.5	$41.5	**$207.7**
TXU	$27.7	$39.4	$39.4	$39.4	$39.4	$39.4	**$196.9**

Details for each category of capital expenditure are set out in the sections below, followed by the Commission's benchmark estimate of overheads.

3.4.6 Renewal of low-pressure mains

Each distributor has forecast capital expenditure for the replacement of mains over the 2003-07 access arrangement period. The resulting forecasts largely reflect the condition and make-up of their network assets, and highlight the difference between their respective asset management strategies. The table below shows the relative size of each distributors' low-pressure network.

TABLE 3.16
GAS DISTRIBUTION MAINS BY TYPE

		LP Network				Other	Totals
		CI	PVC	US	Total	PE & PS	
Envestra Victoria	Km	880	550	180	1610	6189	7799
	%	11.3	7.1	2.3		79.4	
Multinet	Km	1,882	772	625	3,229	5,800	9,029
	%	20.3	8.6	6.9		64.2	
TXU	Km	996	655	597	2,248	5,898	8,146
	%	12.2	8.0	7.3		72.4	

Notes: CI - Cast iron, US – unprotected steel, PS – protected steel, PE – polyethylene, LP- low pressure, Other - medium and high pressure.

As noted above, the Commission conducted a number of meetings with OGS and each distributor (separately) in order to reach a view on what might constitute a reasonable low-pressure mains replacement program for each distributor. In assessing what constitutes a reasonable period to replace a low-pressure distribution system, the Commission has had regard to whether the proposed replacements are necessary to maintain safety and reliability of the system.

The general consensus of views expressed during further consultation is that the service providers in the industry as a whole need to progressively replace cast iron and ductile iron systems. However, the question arises as to the appropriate length of time over which these assets should be replaced. This largely depends on the condition of each distributor's particular assets and the likelihood and extent of potential gas leakage from those assets.

While the distributors have not experienced any major incidents due to gas leaks, the Commission accepts that it is prudent for the distributors to develop and implement a long-term program to progressively replace the cast iron part of the network and thereby minimise the possibility of any major incidents. The Commission understands that while cast iron mains form a significant proportion of the low-pressure system, from a safety and capacity perspective, it is more appropriate to consider the replacement of the low-pressure system as a whole.

Proposals

TXU has advised that the majority of its maintenance costs are a result of its ageing low-pressure network, in particular the cast iron mains. It has further advised that this network needs urgent replacement to meet acceptable safety and reliability targets. In response to questions raised, TXU presented a number of different programs for mains renewal, including its preferred 'Progressive Plan' for renewal replacement, which will result in the complete replacement of cast-iron mains within 16 years.

However, TXU's Progressive Plan shows a reduction in length of mains replaced in comparison to its original proposed program submitted in April 2002, with no corresponding reduction in forecast capital expenditure. Furthermore, regardless of the reducing leakage rate, operating expenditure is forecast to increase from historical levels by approximately 20 per cent. TXU has explained that these differences reflect further detailed analysis that highlights the ability to reduce the leak rate at the expense of having to replace the higher cost mains in the next three years.

Multinet has advised that it needs to replace 540km of low-pressure mains over the 2003-07 access arrangement period to ensure that minimum pressure and reliability requirements continue to be met.

The Commission notes that Multinet has the largest low-pressure system of the three distributors, with more than 30 per cent of its network being low-pressure. Multinet proposes to replace its low and medium pressure system over a period of 40 years, with the low pressure systems to be completed in 30 years. It has also indicated that 80 per cent of its maintenance expenditure is directly related to the low-pressure system.

Envestra's replacement strategy appears to be based on a more reactive approach. Specifically, it proposes to replace approximately 28km of low-pressure mains per annum, unless leakage rates start to increase, in which case the extent of replacement will be increased. Envestra has advised that very few mains are replaced due to unacceptable safety risk and that its approach ensures maximum use of assets.

Envestra has also advised that its replacement strategy is based on the following mix of work:

- *Piece Renewal* - which includes replacing sections of mains discovered during maintenance works to have badly deteriorated. This represents approximately 29 per cent of their replacement works.

- *Feeder Mains* **-** which is the replacement of supply mains to the low-pressure areas. This represents approximately 7 per cent of their replacement works.

- *Block Renewal* **-** which involves upgrading an area from low-pressure to high-pressure. This represents approximately 64 per cent of their replacement works.

Using this replacement strategy, Envestra would replace its low-pressure network over a period in excess of 40 years.

After consulting with the distributors, and based on advice received from OGS, the Commission accepts the overall rates of replacement proposed by TXU (375kms) and Multinet (540kms). In relation to Envestra's proposed replacements (140kms), OGS has expressed the view that a reactive approach to renewing the low-pressure system is not appropriate. A more appropriate approach would be based on a systematic replacement of the low-pressure system giving priority to the most needed area. The Commission shares OGS's views in relation to the Envestra proposal. However, for the purposes of this Final Decision, the Commission has adopted forecasts that are based on the replacements proposed by Envestra. In doing so, the Commission notes that it expects ongoing consultation to occur between OGS and Envestra, and that ultimately the optimal replacement strategy is a matter for them to decide.

Unit costs

Having established an assumption regarding the length of mains to be replaced, the Commission must then consider the assumptions that need to be made in relation to unit costs. The Commission notes that the unit cost of replacing mains will to some extent vary across distributors depending on different environmental factors.

Envestra has submitted a unit rate of $158 per metre, which is significantly higher when compared to approximately $125 per metre for Multinet and $110 for TXU.

The Commission believes that the direct costs should be in the order of $80 -$100. This is based on its experience during the 1998 review, where figures were provided on behalf of the gas distributors.[215] However, the unit costs are outside this range as a result of the allocation of overheads. This has become more apparent by virtue of the Commission's further consideration of the distributors' proposed unit costs.

Removing the TXU's overhead rate of 30 per cent and Multinet's overhead rate of 22 per cent (from the unit costs above) results in direct unit costs of $86 and $101 respectively. The difference in cost between these distributors could be due to a number of factors including ground conditions and population density. The Commission expects that these factors would result in higher unit costs for Multinet.

The Commission considers the direct unit costs implied by each of the two distributor's proposals are reasonable. Based on the length of mains that each distributor proposes to replace, the Commission has adopted forecast direct costs per annum for TXU and Multinet of $6 million and $11 million respectively.

The unit cost implied by Envestra's proposal ($158 per metre including overheads) is much higher than the benchmark unit rates adopted by the Commission for TXU and Multinet. The difference is possibly due to the reactive nature of Envestra's replacement strategy, which is said to result in fewer replacements per annum at the expense of a higher unit cost (relative to a strategy whereby large blocks of mains are replaced in accordance with an accelerated replacement plan). The Commission has assumed a direct unit cost for Envestra in the range of $99-$116 per metre and a total forecast of $22.2 million for this activity.

---

215 Stone and Webster Report on Capital Expenditure 1997. Boston Consulting Group Report to LP to HP Upgade 1995.

These assumptions in relation to the overall replacement to be undertaken over the 2003-07 access arrangement period and the unit costs associated with that replacement program result in the following expenditure forecasts (see table 3.16).

TABLE 3.17
DIRECT COSTS BENCHMARKS FOR MAINS REPLACEMENT

	No. of kilometres	Unit Cost ($/km)	Total ($ million)
Envestra Victoria	160-180	99-116	$22.2
Multinet	540	101	$48.1
TXU	375	86	$32.4

As noted above, the Commission has accepted the distributors' proposed significant increases in capital programs on the basis that it will take appropriate action to monitor the delivery of the programs to ensure that customers are not disadvantaged by under performance.

3.4.7 Growth-related capital expenditure

Capital expenditure relating to growth is generally categorised either as having been initiated by customers (new connections) or required to augment the distribution network. The Commission discusses each of these categories of capital expenditure in turn below.

Customer initiated

The major factors affecting capital expenditure for customer-initiated capital are the specific costs associated with the connection of new customers and the rate of new customer growth.

Connecting customers to the distribution network requires a new main for the purpose of transporting gas from the existing distribution network to a new customer's premises, a service pipe from the new main to a location in the customer's property and a meter (including its associated equipment) to measure the customer's gas consumption. These costs vary according between locations and between different types of customers. The most significant variation occurs between different industrial customers, with meter costs alone ranging from $450 to in excess of $10 000.

The direct costs submitted by each of the distributors for *domestic* customer connections are shown in the table below.

TABLE 3.18

DISTRIBUTORS' PROPOSED DIRECT UNIT COST PER DOMESTIC CONNECTION

	Mains	Services	Meters	Total
Envestra Victoria	*46*	802	190	**1038**
Multinet	*290*	573	139	**1224**
TXU	*554*	359	121	**1365**

Source: Additional information provided in September 2002. Average over 2003-07.

New *mains* are generally associated with the reticulation of new sub-divisions or infill in an existing distribution area. In the case of Envestra and TXU, most of their new mains are expected to be associated with extensions in new estates, while Multinet is expected to install new mains in the existing distribution areas. These costs can vary due to the soil condition and the type of the development.

Based on expert advice, the Commission estimates that costs are likely to be in the range between from $500-600 per customer in the distribution areas where there is a mix of both new estates and infill of the existing distribution area. Where new connections are predominantly infilling of existing areas, the cost per customer would be more likely to be in the range of $200-300. Accordingly, Multinet's and TXU's estimates of both are reasonably consistent with these estimates. However, it is difficult to explain the low mains cost for Envestra, given that it has a similar distribution area as TXU.

The costs associated with the *installation of new services* will also vary according to factors such as soil conditions and, in the case of existing houses, the varying range of properties. The Commission estimates that the unit cost for services ranges from $300-600. Multinet's and TXU's proposed estimates fall within this range (although, only just, in the case of Multinet), whereas Envestra's proposed estimates are in excess of this range. One possible explanation for Envestra's variance might relate to the way costs are allocated between mains and services. In the case of Multinet, its distribution system is in an established area where the development is more likely to be due to dual occupancy and infilling of new housing areas. Costs for services in established areas are generally higher. As a result, Multinet's unit cost can be expected to be at the higher end.

In relation to the *meter installation*, the direct cost comprises the installation of the meter, the meter itself, the regulator and the associated fittings. Based on expert advice, the Commission estimates that the average cost for a meter installation is in the range of $120-140, depending on the size of the meter. The unit cost submitted by TXU falls within this range. However, the costs submitted by Envestra, and to a lesser extent Multinet, are well outside this range.

It is difficult to explain Envestra's unit cost, given that there is also significant variation in the service and mains costs. Envestra's average unit rate is $1 038 including overheads, although Envestra submitted that a direct cost of $1 157[216] per customer is more appropriate to take into account growth when measuring efficiency gains.

The Commission believes that it is reasonable to assume that all three distributors have a similar range of costs for both services and meter installation, given that each of the distributors service customers within Victoria. The key area of difference is likely to relate to the mains and services costs, as it depends on the number of new estates being developed in each distributor's area. Envestra's area covers both the Cranbourne and Berwick areas, which are among the fastest residential development areas. As such the Commission expects that its mains cost would be similar to that estimated by TXU.

On balance, the Commission considers that a reasonable benchmark direct cost for works initiated by domestic customers ranges from $1 100-1 400 per connection. Noting the slight differences between the TXU and Multinet's connection projects and distribution areas, the Commission accepts their estimates of direct costs. As the nature of Envestra's distribution network is similar to that of TXU, the Commission proposes to accept the estimate provided by Envestra in relation to the benchmark adjustment for the purposes of the efficiency carryover calculation namely, a direct cost of $1 157 per customer.

The remaining assumption relates to the number of new connections to which the benchmark unit cost per connection is applied to derive a forecast total capital expenditure for customer (domestic) initiated works. This assumption has been taken from the Commission's conclusions to the demand forecasts in section 3.9 and results in the following forecasts.

TABLE 3.19
FINAL DECISION: AVERAGE DIRECT COSTS BENCHMARKS PER CUSTOMER CONNECTION, 2003-07

	Unit Cost	Connections	Total Costs
Envestra Victoria	$1157	39,138	$45m
Multinet	$1213	39,912	$44m
TXU	$1344	64,075	$86m

As noted above, the mains and service costs for an industrial customer can vary considerably due to the location of the customer. The industrial meter cost could also vary considerably (between $450 to $10 000) due to the size and pressure of the meter and the associated equipment.

216 Information provided in September 2002.

Noting that service costs and the meter installation costs can vary significantly, Envestra has the lowest cost per industrial customer compared to both TXU and Multinet. Based on this, and the fact that the forecast is consistent with Envestra's historical costs, the Commission accepts Envestra's average forecast unit cost of $6 675. In addition, the Commission estimates that the range of direct meter cost is between $6 000-14 000 depending on the mix and cost of meters. It therefore proposes to adopt Multinet's and TXU's proposed estimates of $8 633 and $13 000 respectively.

Applying these unit costs to the number of connections results in total capital expenditure forecasts for industrial customers as per the table below.

TABLE 3.20
TOTAL INDUSTRIAL CUSTOMERS CAPITAL EXPENDITURE
($ million in July 2001 prices)

	2003	2004	2005	2006	2007
Envestra Victoria	4.6	4.6	4.6	4.6	4.6
Multinet	2.3	1.6	1.7	1.5	1.4
TXU	2.1	1.8	2.0	1.9	1.9

Augmentation

The direct forecast expenditures submitted by Envestra and TXU with respect to augmentation works are $7.0 million[217] and $4.9 million respectively, with the former including $1.4 million for the reticulation of a town in 2005 and 2006. Envestra's proposal includes various projects such as upgrading of its field regulators and augmenting supply constraints areas. As such, the Commission accepts the proposals as submitted by Envestra.

TXU has similar proposals to Envestra in relation to upgrading its field regulators and augmenting supply constraints areas. The Commission proposes to accept TXU's proposed estimate on the basis of the project details provided.

The most significant augmentation expenditure is that proposed by Multinet, which for 2003-07 comprises $47.78 million for the distribution system and $8.17 million for the transmission system. Included in the augmentation expenditure ($47.78 million) is $27.17 million[218] for the upgrading of the low-pressure system due to capacity constraints. Multinet identified this cost separately whilst TXU and Envestra have included the cost as part of their renewal expenditures. The Commission has considered Multinet's expenditure for the low-pressure upgrading as part of the renewal expenditure.

217 Envestra, Summary Submission, 12 September 2002. Expenditure in original submission was $9.34 million.

218 Multinet advised that approximately 50 per cent of the distribution augmentation budget is for the low pressure upgrading.

Leaving aside replacement of low-pressure mains, the remaining distribution expenditure is forecast to be $20.5 million and includes expenditure for the replacement of custody transfer meters and upgrading of field regulators. The cost also includes new supply mains and reinforcement. On the basis of the detailed project information provided by Multinet, the Commission has decided to accept this expenditure.

In the case of the transmission pipeline, Multinet states that the work is necessary due to a transmission constraint. Whilst in previous years, Multinet has been able to augment its system through gas injected from the Envestra network at times of peak demand, this option will not be available in the next access arrangement period. The Commission has been advised that the direct cost associated with the pipeline is considered reasonable using an industry standard for estimating pipeline costs and allowing for construction through metropolitan areas. Adopting this assumption results in a forecast of $28.2 million.

TABLE 3.21
FORECAST CAPITAL EXPENDITURE NETWORK AUGMENTATION
($ million in July 2001 prices)

	2003	2004	2005	2006	2007
Envestra Victoria	1.2	1.1	2.1	2.0	0.7
Multinet	3.5	11.9	3.5	4.3	4.9
TXU	1.2	1.3	1.2	0.5	0.6

3.4.8 Meters

The distributors' proposals each include estimated increases in the costs associated with the replacement and repair of meters. Some of these increases are attributable in part to assumptions about the future regulatory arrangements in relation to meter testing.

By way of background, the Distribution System Code allows for meters to be installed for the period of its initial life (15 years). Should a distributor decide to retain a meter in service beyond this period, it must ensure that the meters of that type (or 'family') meets the requirement of an approved sampling plan. The sampling plan as approved by the Commission requires the meter family to pass an accuracy test at 100 per cent of the badge capacity of the meter.

In 1999, the Commission, following consultation with the gas industry, including the distributors, revised the Distribution System Code to include the requirement that the error limit range of meters be established at (i) 20 per cent and (ii) 100 per cent of the badge capacity of the meter. This has created an anomaly between the requirements of the Distribution System Code and the sampling plan approved by the Commission. In addition, due to the more stringent requirement, the distributors are estimating that this will have a significant impact on the management and the expenditure of their meter replacement program.

The Commission considers that while the more stringent requirement would, in the long term, improve the overall performance of meters in the field, it is conscious of the cost to the consumer and the marginal short-run benefit of this requirement. From some of the information provided to the Commission by the distributors, this stringent requirement could result in additional meters being removed from the field in excess of what is required under the current sampling plan. The Commission has concerns about the ability of the businesses to meet this additional workload and whether the meter suppliers could provide these meters in the short term. As such, at least for the 2003-07 access arrangement period, the Commission does not propose that the distributors should change their sampling plan to incorporate the more stringent requirement.

However, to be able to assess the overall effect, the Commission proposes the following:[219]

- the current sampling plan should henceforth incorporate testing at both 20 per cent and 100 per cent of the badge capacity of the meters, with the criterion for retaining the meter at 100 per cent of the badge capacity of the meter to be retained.
- the test results for both 20 per cent and 100 per cent for that meter family should be provided to the Commission to determine the overall effect of the 20 per cent testing.
- new and repaired meters should continue to be tested both 20 per cent and 100 per cent of the badge capacity of the meter.

The Commission considers that once the effect of the 20 per cent testing has been assessed, it is most likely to be introduced in the following regulatory period.

Comparison of distributors' capital & operating expenditure

Based on the above analysis, the Commission has requested that the distributors submit their five-year expenditure (summarised in the following table). The table includes details for both domestic and industrial/commercial meters. TXU and Envestra have capitalised the repair and re certification of meters, whilst Multinet has chosen to consider it as maintenance expenditure.

TABLE 3.22
DISTRIBUTORS' PROPOSED METER EXPENDITURE, 2003-07

Distributor	No of meters replaced	Capital Expenditure (03-07)
TXU	153 918	$21.5 million
Envestra Victoria	141 968	$19.7 million
Multinet	234 580	Capex $15.2 million Opex $27.3million

219 The processes for giving effect to this proposal are pursuant to the Distribution System Code rather than through the distributors' Access Arrangements.

In estimating their expenditure, the distributors have made assumptions regarding the percentage of meters removed from the field that can be repaired which then has an impact on the number of new meters that each business needs to purchase. TXU and Envestra have assumed 50 per cent of the meters are repairable whilst Multinet has assumed 90 per cent.

On 10 September 2002, the Commission requested that each of the distributors complete a template of forecast capital expenditure for 100 per cent badge capacity only. The request related to each company's average unit (meter) replacement rate and a breakdown of direct and overhead cost.

In response, the only distributor to forecast meter replacement and costs consistent with the information provided in their original Access Arrangement Information was TXU. As a result, for the purpose of establishing the recommended forecast expenditure for meter replacement, the Commission relied on information supplied previously.

For both industrial and domestic meters, the unit cost information provided by the distributors varied widely and also applied different overheads to the direct cost (see table 3.22).

TABLE 3.23
DISTRIBUTORS' PROPOSED DIRECT UNIT COSTS FOR METERS

	Domestic Unit Cost	Industrial Unit Cost
Envestra Victoria	$107	$2435
Multinet	$144	$4302
TXU	$128	$794

Both Envestra and TXU have capitalised the cost of repairing meters. As such, the unit cost is dependent on the business' assumption on the ratio of new versus repaired meters. In contrast, Multinet has chosen to include the repair of meters as an operating expenditure. As such, the cost shown for Multinet in the table above relates only to the cost of new meters being purchased and installed.

The unit cost is therefore dependent on the ratio of new versus repaired meters and its associated cost. The Commission estimates that the efficient direct cost for replacing domestic meters are likely to be in the following ranges:

- Unit cost for a repaired domestic meter $85-$95
- Unit cost for a new domestic meter $115-$125
- No of repairable meters 70-80 per cent

Using the unit cost above, the mix between repairable and new meters and the number of meters to be repaired, the Commission has estimated the expenditure for the distributors' proposed meter replacement program. The tables below set out the distributors' submitted costs and the Commission's estimate of the efficient level of expenditure associated with the meter replacement program.

TABLE 3.24

COMPARISON OF DISTRIBUTORS' PROPOSED AND FINAL DECISION METER COSTS

	Meter	Number Replaced	Unit Rate $/meter		Total Expenditure $m	
			Submitted	Estimate	Submitted	Estimate
Envestra	I&C	1,968	2435	1431	4.8	2.8
	Total	**141,968**			**19.7**	**16.5**
	Capex					
	Domestic	28,927[220]	144	119	4.2	2.7
Multinet	I&C	2,260	4302	1625	9.8	3.7
	Total	**31,187**			**14.0**	**6.4**
	Opex					
	Domestic	260,345[221]	114	95	29.6	19.4
	I&C	5,075	708	600	3.6	3.0
TXU	Domestic	148,757[222]	128	102	19.1	15.2
	I&C	5,161	794	798	4.1	4.1
	Total	**153,918**			**23.2**	**19.3**
	Domestic	140,000[223]	107	98	14.9	13.7
	Total	**265,420**			**33.2**	**22.4**

Note: The Commission's benchmark estimate of meter cost has been calculated on the basis of the proportion of repairable maters to new meters.

As previously noted, the Commission has accepted the distributors' proposed significant increases in capital programs on the basis that it will take appropriate action to monitor the delivery of the programs to ensure that customers are not disadvantaged by under performance.

3.4.9 Other capital expenditure

The distributors have submitted forecast expenditure under the category of 'Other' costs, which includes the costs associated with implementing the GSL payments scheme.

220 100% and 20% badge rate testing
221 100% and 20% badge rate testing
222 100% badge rate testing only
223 100% badge rate testing only

Envestra has forecast ‘other’ expenditure[224] of $6.1 million, which includes $3.0 million for upgrading telemetry equipment and the purchase of miscellaneous equipment. The remaining expenditure of $3.1 million related to IT-related equipment. Multinet has forecast ‘other’ expenditure[225] at $25.7 million, with $4.6 million for SCADA and network related equipment, $16.6 million for IT expenditure and a further $4.5 million for office equipment. Multinet stated that this expenditure did not include costs associated with establishing systems for FRC.

TXU’s expenditure for this category is $6.5 million, with $2.0 million for SCADA and other network related equipment and IT expenditure of $3.5 million and non-network related expenditure of $1.3 million.

TABLE 3.25
DISTRIBUTORS’ PROPOSED ‘OTHER’ EXPENDITURE, 2003-07
($ million in July 2001 prices)

	Envestra Victoria	Multinet	TXU
Network Related	3.0	4.6	2.0
IT	3.1	16.6	3.5
Non Network	-	4.5	1.3
Total	6.1	25.7	6.5

Both TXU and Envestra have proposed a similar level of other expenditure. The Commission considers that it is reasonable to expect that each of the three businesses (TXU, Envestra and Multinet) would be likely to have inherited similar equipment and IT systems when they were purchased, and that any upgrade or changes to the IT system would also be similar. On that basis, the Commission proposes to accept the expenditure for both Envestra and TXU.

However, in relation to Multinet, the expenditure for all three categories is higher than the other two businesses. The Commission accepts that Multinet may have a more established distribution system that may require additional operational control equipment (ie. SCADA), and as a result proposes to accept its forecast network-related expenditure. In relation to IT expenditure, the Commission believes that the expenditure should be in the same order of magnitude of the other distributors. As such, the Commission proposes that forecast to be adopted of Multinet’s IT expenditure should be $4.1 million and its non-network related expenditure should be $1.6 million.

224 Information provided on 13 September 2002. Expenditure in the original April 2002 submission was $2 million.

225 Information from the distributors’ original Access Arrangement Information.

TABLE 3.26
COMPARISON OF MULTINET'S FORECAST 'OTHER' CAPITAL EXPENDITURE AND FINAL DECISION
($ million in July 2001 prices)

	Multinet	
	Proposed	**Commission's final decision**
Network Related	4.6	4.6
IT	16.6	4.1
Non Network	4.5	1.6
Total	25.7	10.3

3.4.10 Forecast overheads

The reported capital expenditure for 2001 includes overheads that equate to approximately 17 to 22 per cent of the reported total capital expenditure. That is, overhead amounts of $4.9 to $6.5 million on works in the order of $20 to $25 million across the three distributors. These overhead amounts can include corporate overheads as well as direct overheads, such as costs relating to asset management, planning and design. In the case of TXU, its allocated overheads for 2001 include approximately $1 million of corporate overheads.

TXU's forecasts apply a rate of 30 per cent to the capital expenditure to reflect its estimate of the overheads to be incurred in undertaking the proposed works. Multinet has used the same percentage as it applied in 2001. Both suggest that overhead costs are directly proportional to the level of capital works activities.

The Commission does not consider that this is a reasonable basis for allocating overheads on the basis that it does not consider that overhead costs (especially corporate overheads) will increase proportionately with capital expenditure.

For instance, TXU capital expenditure for renewal for 2001 is approximately $1 million and it has allocated overheads on the basis of 20 per cent in 2001. Therefore, using the overhead rate of 20 per cent including corporate cost would imply an expenditure of $200 000 on overheads. While it is expected with an increased workload that there will be some marginal increase in the direct overhead, it can also be expected that the corporate overhead should stay the same.

Applying a 20 per cent overhead rate to TXU direct capital expenditure of $6 million would imply a overhead expenditure of $1.2 million. Excluding the corporate overhead activities, the current industry practice is that support activities include such functions as planning, quality supervision, technical design and contract management. Whilst it is reasonable to expect that there may be some increase in activities for staff involved with the above activities, it is also reasonable to expect that areas such as contract management and technical design would increase only marginally. As a result, the Commission does not consider it is appropriate for overhead expenditure to increase in the same proportion (ie. 6 times) as the direct capital expenditure.

The Commission accepts that expanding the capital works program will result in an increase in some overheads, and accordingly has adopted a benchmark amount based on the reported overhead expenditure in 2001 with an increase of 10 per cent. The total overheads estimated over the five year period using this assumption relative to the amounts estimated by the distributors is shown in the table below.

TABLE 3.27
COMPARISON OF DISTRIBUTORS' PROPOSED CAPITAL RELATED OVERHEADS AND FINAL DECISION
($ million in July 2001 prices)

	Distributor proposed	Commission assumption
Envestra Albury	0.7	0.7
Envestra Victoria	27	27
Multinet	44	36
TXU	56	28

3.5 Establishing the 2003 capital base

3.5.1 Gas Code requirements

The distributors' regulatory asset values (or capital base) represent the value of the investment upon which the owners of the business earn a return, and the value that is returned to the owners of the assets over their economic life (as depreciation). These capital-related components account for about 70 per cent of the cost of providing reference services. In assessing the distributors' proposed Revisions, the regulatory values for the distributors' assets used to provide the reference services need to be updated as at the start of the next regulatory period (commencing 1 January 2003), and projected forward over that period.

The Commission determined the regulatory value of the assets that existed as at 1 January 1998 in the course of approving the existing Access Arrangements in 1998. In determining those values, the Commission had regard to the factors in section 8.10 of the Gas Code, including the values that would be derived by Depreciated Optimised Replacement Cost and Depreciated Actual Cost valuations, international best practice, the reasonable expectations of all parties, and the impact on the economically efficient utilisation of gas resources. It also considered how to best achieve the objectives in section 8.1, and considered the factors set out in section 2.24 of the Gas Code. As a consequence having determined an initial capital base for each of the distributors in its 1998 review, the regulatory values of the distributors' assets in existence at that time is non-controversial – the values determined in 1998 are now set and cannot be re-opened in the current or future reviews.

The capital bases (in 1 January 1998 dollars) determined for each of the distributors as at 1 January 2002 were as follows:

- Multinet $740.2 million

- Stratus $580.0 million
- Westar $631.7 million

In the Draft Decision, the Commission noted that many of the methodological issues associated with updating the distributors' regulatory asset value for the forthcoming review are prescribed in the Gas Code[226] or in the relevant fixed principles in the distributors' existing Access Arrangements.[227] Broadly, the Commission is required to use the following formula in determining the opening regulatory asset base as at 1 January 2003:

The value of the capital base as at 1 January 1998

Plus

Capital expenditure over the first regulatory period, net of customer contributions (surcharges) and disposals

Less

Regulatory depreciation over the first regulatory period

Less

Redundant capital

In addition, as the existing reference tariffs were designed to deliver a real (rather than nominal) return on assets, an adjustment needs to be made to compensate investors for the change in the general price level (inflation) over the first regulatory period.[228]

3.5.2 Background and the distributors' proposals

In its previous consultation papers, the Commission discussed a number of issues, and made a number of proposals, associated with updating the regulatory asset values.

First, the Commission must determine whether to approve the distributors' proposed approach to adjusting for inflation over the first regulatory period. In its previous consultation papers, the Commission detailed its proposals for adjusting the regulatory asset base for inflation, as well as for dealing with inflation when projecting costs and revenue forward over the next regulatory period.[229] The key principles proposed were that:

- all calculations (except for calculations related to company tax) would be undertaken in 1 July 2001 (constant) prices, with the allowance for inflation to establish first period tariffs provided through the price controls.
- the measure of actual inflation would reflect that used in the current price controls (ie. the price level at the end of any quarter as the level of the ABS CPI (Average of Eight State Capitals) nine months previously); and

226 The most relevant section is 8.9, which also refers to other relevant provisions of the Gas Code.
227 These are contained in clause 9.2(b)(3) of the Tariff Order.
228 Section 8.5A of the Gas Code.
229 This adjustment leaves out the question of whether some adjustment should be made for the one-off GST-related 'spike' in measured inflation, which is discussed below.

- expenditure and revenue (whether forecast or actual) would be forecast to have been incurred or received in the middle of the relevant year.

Second, the Commission must form a view about the extent to which the distributors' capital expenditure over the first regulatory period meets the requirements of the Gas Code, and hence can be included in their regulatory asset bases. Amongst other things, this requires the Commission to form a view as to whether the expenditure incurred was prudent and efficient.[230]

In its consultation papers prior to the Draft Decision, the Commission expressed the view that it considered it appropriate to infer that the distributors' capital expenditure would meet the Gas Code requirements.[231] While users expressed concern with such a 'hands-off' approach, the Commission expressed its view that the reliance upon well-designed incentives to satisfy the requirements of the Gas Code provides a more effective means of ensuring that its statutory obligations are met.[232]

Third, the Commission also noted that it requires an assumption about the extent of *regulatory depreciation* and *disposals* over the first regulatory period. Regarding depreciation, the Commission proposed that the allowance reflected in the reference tariffs over the first period should be deducted from the regulatory asset base. It noted that such a view is consistent with the *financial capital maintenance* concept, whereby the guiding principle applied to the various capital-related costs is to preserve the financial value of past investments, with no necessary link to the physical assets employed.

The Commission also proposed that the regulatory value of the distributors' assets be adjusted to reflect the proceeds of disposals, rather than some form of regulatory book value (if this exists) – that is, to interpret disposals as an alternative form of return of investment funds. Technically, such disposals constitute redundant capital as per section 8.27 of the Gas Code. As such, the Commission must take into account the uncertainty caused and its effect on service providers, users and prospective users. It also noted that this proposal (as well as that for regulatory depreciation) is administratively simple, as it would avoid the need to divide the regulatory asset value into specific assets, and for the Commission to undertake detailed oversight of the distributors' regulatory accounting practices.[233]

Lastly, the Commission raised the issue of whether it is appropriate to remove the GST-related spike in inflation when adjusting the distributors' asset values for the change in the general price level over the period from 1998 to 2003. While the Commission expressed a preference for removing this 'spike' in Consultation Paper No. 1,[234] it noted in the Position Paper that this was a complex matter and that it wished to leave its views open.[235]

---

230 The relevant principles in the Gas Code are contained in section 8.16.

231 Op. cit., Position Paper, pp.29-31.

232 A related matter is the assumption that is made about capital expenditure in the last year of the regulatory period, given that this information will not be available at the time the review is completed. The assumption adopted about the last year of expenditure is an integral component of the Commission's incentive arrangements.

233 Op. cit., Position Paper, pp.32-33.

234 Op. cit., Consultation Paper No. 1, pp.41-44.

235 Op. cit., Position Paper, pp.34-35.

Regarding the *general treatment of inflation* when rolling-forward the regulatory asset bases, TXU and Multinet's proposed Revisions adopted the Commission's proposed approach. However, Envestra's proposed approach included a different assumption about the timing of capital expenditure within each year, and did not adjust the original 'money of the day' forecasts of regulatory depreciation to take account of the difference between forecast and actual inflation. However, in a subsequent letter to the Commission, Envestra proposed that the Commission should apply the methodology described above.[236]

In their proposed Revisions, each of the distributors included all of their capital expenditure undertaken over the first regulatory period in their rolled-forward regulatory asset bases (net of surcharges). Each of the distributors also adopted the Commission's proposal of adjusting the regulatory asset bases for the regulatory depreciation allowance factored into reference tariffs for the first regulatory period.

Regarding disposals, all distributors stated in their proposed Access Arrangement Information that they deducted the regulatory book value of assets disposed, rather than the proceeds from those disposals as the Commission had proposed. Envestra stated that the use of proceeds is inconsistent with 'general regulatory principles'. It also argued that this approach, amongst other things, removes the incentive for businesses to achieve the best sale price for assets disposed and could result in negative values for the remaining assets given that regulated assets have often been sold at multiples of the regulatory value in the past. Further, it suggested that adopting the regulator's approach will lead to 'gaming' over whether any sale premium is allocated to regulated or non-regulated assets.[237]

Finally, none of the distributors raised the matter of the GST-related spike in inflation in their submissions.

3.5.3 Draft Decision

As noted above, all of the distributors accepted the method of adjusting for inflation and for regulatory depreciation over the first regulatory period the Commission had proposed in earlier consultation papers. Accordingly, these methods were reflected in the Draft Decision.

Regarding capital expenditure, the Commission noted that it remained of the view that the most effective means of ensuring that the distributors' capital expenditure meets the requirements of the Gas Code is to provide the distributors' with the commercial incentives to achieve this outcome, which existed over the first regulatory period. Accordingly, the Commission concluded that it was appropriate for the distributors to include in their regulatory asset bases their actual capital expenditure (net of customer contributions, or surcharges) over the period. However, the Commission noted that it has not had a robust reporting regime in place over the first regulatory period, and so it would need to obtain independent verification of the results prior to the Final Decision.

[236] Letter from A. Staniford (Envestra) to G. Wilson (ESC), 19 June 2002.
[237] Envestra, Access Arrangement Information, 2 April 2002, p.51.

Regarding disposals, the Commission confirmed the views it expressed prior to the Draft Decision, and deducted the proceeds of disposals from the distributors' regulatory asset bases. The Commission noted that many of Envestra's arguments (such as the concern that there may be a negative asset value) appear to be more relevant to a sale of part or all of one of the distributors, together with all of its assets, goodwill, and the licence responsibilities associated with that ongoing activity. In that situation, it would be appropriate for the regulatory value of the business (or the sum of the regulatory values of the new businesses) to remain equivalent to the regulatory value of the original business. Disposals of the business or parts of the business do not constitute redundant capital. In contrast, it noted that the Commission's use of the term 'disposals' refers to the sale of excess assets in the normal course of business, such as excess computers and other hardware when systems are upgraded, or cars and trucks at the end of their useful lives, all of which would be expected to be relatively minor items.

Regarding the GST-related inflation spike, the Commission expressed the view that a failure to adjust measured inflation for the effects of the GST may provide distributors with a windfall gain. However, on balance, the Commission proposed not to adjust measured inflation over the previous regulatory period to attempt to remove the impact of the GST-related spike in prices. In reaching this conclusion, the Commission noted that it placed significant weight on the implications of the financial capital maintenance concept, as well as the desirability of adopting a simple approach wherever possible. In addition, the Commission noted the complexity associated with the matter and accordingly proposed that a more a conservative approach was warranted.

3.5.4 Responses to Draft Decision

Regarding disposals, Envestra proposed revising the wording of its fixed principles that adopted the Commission's preferred approach of adjusting the capital base for the proceeds of disposals. Consistent with the intention of the Commission's proposals, it provided that a disposal of all or part of the business (rather than minor redundant assets) would be an exception to this rule.[238]

Submissions from a number of customer groups reiterated the concerns expressed throughout the consultation process with placing too much weight on incentives to infer that expenditure has been efficient. For example, Pareto Associates (for the Customer Energy Coalition) commented that:

> It is, therefore, of concern that the ESC relies too heavily on assumptions that positive incentives (for the [distributors] to reduce costs to efficient levels) work equally well for all [distributors] all of the time and always to the ultimate benefit of consumers – without testing this assumption in the same way that all UK regulators do.[239]

A submission by the Energy Users Coalition expressed a similar concern:

> The ESC's assumptions that the positive incentives for the gas businesses to reduce costs to efficient levels, will work equally well for all companies all the time and

238 Envestra, Response to the Draft Decision, p.37.

239 Pareto Associates, Customer Energy Coalition Response to the Draft Decision, 23 August 2002, p.13.

> always to the ultimate benefit of customers, would appear unworldly and unrealistic. Unlike other regulators … the ESC has not sought to test these very broad and altruistic assumptions and has followed the high level concepts …[240]

3.5.5 Further analysis

As there were no further submissions on these matters, the Commission has adopted the approach set out in the Draft Decision with respect to adjusting the capital base for inflation, regulatory depreciation and disposals for the reasons summarised above, and in more detail in the Draft Decision.[241]

Regarding capital expenditure, the Commission has addressed previously the concerns of users about using incentives to infer that expenditure meets the requirements of the Gas Code.[242] The Commission appreciates the users' concerns about the clarity of incentives in the first regulatory period. However, it remains of the view that the commercial pressures on the distributors in the first regulatory period would have sufficient disciplined capital expenditure to allow it to infer that the particular projects undertaken would have met the requirements of the Gas Code. The Commission confirms its previous conclusions on this matter.

As noted above, information on the actual capital expenditure for 2002 is not available at the time of this Final Decision, and so an assumption about this expenditure is required. As the Commission has noted previously, the assumption that is made about 2002 capital expenditure is an integral component of the incentive arrangements included in this Final Decision. Accordingly, this issue is discussed in section 3.8.

3.5.6 Rolled-forward asset values

The distributors' rolled-forward asset values for the period from 1 January 1998 to 31 December 2002, in light of the discussion above, are shown in table 3.28.

---

240 Energy Users Coalition, Supplementary Response to the Draft Decision, 6 September 2002, p.1.

241 Draft Decision, pp.85-93.

242 Position Paper, pp.29-31.

TABLE 3.28

ROLLED-FORWARD ASSET VALUES ADOPTED IN THIS FINAL DECISION ($ million in July 2001 prices)

Envestra Victoria	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Opening RAB	630.1	648.1	656.2	658.9	661.0	665.6	671.4	676.3	680.1	682.8
Net Capex	37.5	29.7	26.4	26.3	29.7	28.4	28.4	28.4	28.4	28.4
Proceeds from Disposals	0.0	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Regulatory Depreciation	19.5	21.6	23.2	24.2	25.0	22.6	23.5	24.6	25.7	26.8
Closing RAB	648.1	656.2	658.9	661.0	665.6	671.4	676.3	680.1	682.8	684.5
Envestra Albury		**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Opening RAB		23.94	23.97	24.22	24.39	24.50	24.31	24.23	24.26	24.24
Net Capex		0.74	0.95	0.88	0.81	0.59	0.71	0.86	0.84	0.76
Proceeds from Disposals		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Regulatory Depreciation		0.71	0.70	0.70	0.70	0.78	0.80	0.83	0.86	0.89
Closing RAB		23.97	24.22	24.39	24.50	24.31	24.23	24.26	24.24	24.11
Multinet	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Opening RAB	804.1	805.4	803.3	782.6	777.3	776.6	786.4	794.3	801.0	806.6
Net Capex	28.7	26.2	23.1	24.7	29.9	41.6	41.6	41.6	41.6	41.6
Proceeds from Disposals	0.1	0.1	14.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Regulatory Depreciation	27.2	28.2	29.1	29.9	30.7	31.8	33.7	34.9	36.2	37.4
Closing RAB	805.4	803.3	782.6	777.3	776.6	786.4	794.3	801.0	806.4	810.6
TXU	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
Opening RAB	686.2	697.0	705.6	716.1	722.1	738.8	753.9	768.6	783.0	797.0
Net Capex	32.0	30.4	33.4	29.7	41.0	39.4	39.4	39.4	39.4	39.4
Proceeds from Disposals	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Regulatory Depreciation	20.9	21.9	22.9	23.7	24.2	24.3	24.7	25.0	25.4	25.7
Closing RAB	697.0	705.6	716.1	722.1	738.8	753.9	768.6	783.0	797.0	810.7

3.6 Rate of return

This section summarises the assumption adopted by the Commission in this Final Decision for the rate of return assumed in the assessment of the distributors' reference tariffs, and its reasons for adopting that assumption. It also summarises the views reached by the Commission on related matters, such as the methodology employed to derive an allowance for company tax liabilities over the next regulatory period, and whether an additional allowance in relation to 'excluded events' is warranted. The full reasons for the Commission's final conclusions on these matters, including its consideration of the issues raised by distributors and others in their responses to the Draft Decision, is provided in Appendix C.

This section also summarises the views reached by the Commission on the question of the technical formula that is used to generate the total revenue that is then used to assess reference tariffs, and the related issue of whether an allowance in respect of working capital is required. This summary is set out in section 3.6.4. The full reasons for the Commission's final conclusions on these matters, including its consideration of the issues raised by distributors and others in their responses to the Draft Decision, is provided in Appendix D.

The Gas Code states that the rate of return on the regulatory value of the distributors' assets (the capital base) that is factored into reference tariffs should comply with the following principles:[243]

> The Rate of Return used in determining a Reference Tariff should provide a return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the Reference Service (as reflected in the terms and conditions on which the Reference Service is offered and any other risk associated with delivering the Reference Service).
>
> By way of example, the Rate of Return may be set on the basis of a weighted average of the return applicable to each source of funds (equity, debt and any other relevant source of funds). Such returns may be determined on the basis of a well-accepted financial model, such as the Capital Asset Pricing Model. In general, the weighted average of the return on funds should be calculated by reference to a financing structure that reflects standard industry structures for a going concern and best practice. However, other approaches may be adopted where the Relevant Regulator is satisfied that to do so would be consistent with the objectives contained in section 8.1.

The 'return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the Reference Service' is also known as the opportunity cost of capital, or the cost of capital. The *opportunity cost of capital* associated with an asset is the return investors would expect to receive from that project in order to justify committing funds.[244] In turn, this depends upon the aggregate demand and supply of investment funds, as well as the risk of cash flows generated by the project relative to the risk associated with other assets. Unlike the price for most goods and services, the market price for investment capital cannot be observed. Rather it needs to be *estimated* from information available from the capital markets. It is important to note that neither the company, the regulator nor customers can determine the cost of capital — it is a market price for investment funds that can only be inferred from the available market evidence.

With respect to taxation, the models drawn from finance theory and practice for estimating costs of capital provide an estimate of the *after-tax WACC* for a project. In contrast, the price controls to be incorporated into the distributors' revised access arrangements need to include an allowance in relation to the distributors' company tax obligations. Accordingly, an assumption needs to be made about the taxation liabilities incurred in providing the regulated services over the regulatory period. This matter is addressed in section 3.6.2.

243 Sections 8.30-8.31 of the Gas Code.

244 The term *weighted average cost of capital* (WACC) is often used to refer to the cost of capital of an asset because part of the asset returns become payments to the debt providers, and the residual flows to the equity providers. The Commission uses the terms 'cost of capital' and WACC interchangeably throughout this document.

A cornerstone of modern finance is that much of the risk (or volatility) associated with the earnings to a particular asset can be eliminated at no cost merely by holding that asset as part of a diversified portfolio. Such *diversification* implies that only that portion of risk that is associated with economy-wide events affects the cost of capital: as the remaining volatility in an asset's earnings can be eliminated at no cost, investors cannot command a return for accepting the risk associated with events that are unique to a particular asset.

That said, throughout its discussion of the analysis of risk, the Commission has noted that a separate issue relates to whether the return that investors should expect under the new reference tariffs corresponds to its estimate of the cost of capital associated with those activities. In theory, this requires a view to be taken net of the impact on returns of all potential events that have not been considered in the expenditure and revenue forecasts – which the Commission has referred to as 'excluded events'. Whether such events warrant some form of adjustment to reference tariffs is an empirical matter. The Commissions final conclusions on this matter are set out in section 3.6.3.

3.6.1 After-tax cost of capital

Table 3.29 sets out the inputs the Commission has used to estimate the costs of capital associated with the distributors' regulated activities, alongside the equivalent assumptions adopted by the distributors in their proposed Access Arrangement Revisions, and the equivalent parameters adopted by the Commission in its 1998 decision and in the Draft Decision.

TABLE 3.29
ESTIMATED COSTS OF CAPITAL ASSOCIATED WITH THE DISTRIBUTORS' REGULATED ACTIVITIES

	1998 Decision (Victoria)	Envestra (Victoria and Albury)	Multinet	TXU	Draft Decision	Final Decision
Real risk-free rate	3.41%	3.51%	3.50%	3.25%	3.50%	3.4%
Equity beta	1.2	1.16	1.15	1.15	1	1
Equity premium	6.0%	7.3%	7.0%	6.0%	6.0%	6.0%
Debt margin	1.2%	1.65%	1.65%	1.65%	1.4%	1.7%
Gearing (debt/assets)	60%	60%	60%	60%	60%	60%
Real 'Vanilla' WACC	**7.0%**	**7.9%**	**7.7%**	**7.0%**	**6.7%**	**6.8%**

The form of the cost of capital adopted by the Commission in this Final Decision is a real, after-tax WACC. The distributors receive compensation for inflation through being permitted to raise prices to reflect inflation during the regulatory period, and through adjustments to the value of their regulated assets for inflation at price reviews (as discussed in section 3.4). As noted above, this form of the WACC requires an allowance for taxation to be included directly in the distributors' revenue benchmarks – this issue is discussed below.[245]

The Commission's estimate of the costs of capital associated with the distributors' regulated activities is marginally lower than that adopted during the 1998 review, but higher than that adopted in the Draft Decision. The reasons for these differences, and the differences in the assumptions adopted by the Commission and the distributors' proposals, are summarised below.

Real risk free rate

The Commission has derived its proxy real risk free rate as the average of the redemption yield on inflation-indexed bonds over the last 20 trading days to 6 September 2002. This methodology is largely unchanged since its 1998 decision,[246] and has resulted in a proxy real risk free rate that is also largely unchanged.

Multinet and TXU have adopted the same methodology as that proposed by the Commission. Envestra proposed to derive a real risk free rate by deducting its forecast of inflation from nominal bond yields. However, the Commission considers the use of inflation-indexed bonds is more appropriate as these permit a direct observation of the real risk free rate from current market evidence and avoid the need for an independent assumption about future inflation. The Commission's approach is also objective and capable of being replicated across decisions and industries. As a result, it reduces uncertainty associated with the regulatory process. At the present time, the Commission's methodology for deriving the proxy real risk free rate has led to a higher assumption than would have followed from the application of Envestra's preferred methodology (by 0.3 percentage points).

Equity premium

The Commission has adopted the same assumption about the equity premium as it did in 1998, namely 6 per cent (inclusive of franking benefits). Apart from the issue of franking benefits (which is discussed below), TXU adopted the same assumption, whereas both Envestra and Multinet assumed a higher equity premium in their access arrangement proposals. The distributors' subsequent views on the magnitude of the equity premium are discussed in Appendix C.

---

245 The form of WACC adopted is: $WACC = R_e \frac{E}{V} + R_d \frac{D}{V}$. Under this form of WACC, all tax-related matters are reflected in the revenue benchmarks.

246 In its 1998 decision, the Commission used inflation-linked bonds, but sampled rates over a two-month period rather than 20 days.

The difference in the Commission's assumption about the equity premium and that adopted by Envestra and Multinet turns largely on differences in opinion as to the weight to be applied to point estimates of the long-term average of the equity premium in Australia. While the Commission has placed weight on historical returns – as it did in its 1998 decision – it has also considered other evidence, and applied weight according to their relevance.

The relevant evidence taken into account by the Commission included evidence on the assumption about the equity premium made by market practitioners. This evidence included advice by Mercer Investment Consulting on the assumptions it uses in making its asset allocation recommendations and its sampling of opinions by other market practitioners, as well as the results of a formal survey of market practitioners undertaken by Jardine Fleming Capital Markets (which had not been considered prior to the Draft Decision). Both of these sources suggested that most market practitioners adopt an assumption about the equity premium that is lower than the assumption of 6 per cent that the Commission has adopted in previous decisions and in the Draft Decision. However, the Commission does not consider this evidence is sufficiently persuasive to revise its past assumption about the equity premium, particularly when weight is placed upon the long-term consequences of the Commission's decisions, and so has retained its assumption of 6 per cent for the equity premium.

Proxy beta

The most significant difference between the assumptions adopted in the 1998 decision and this Final Decision relates to the proxy equity beta. This change in assumption is a consequence of the additional information from Australian capital markets that has become available on the relative risk of regulated gas distributors. While in 1998, the Commission's primary point of reference was a UK regulatory decision, there are now five companies listed on the Australian Stock Exchange that are considered sufficiently comparable and for which empirical beta estimates are available.[247]

The information now available from the capital markets suggests that the assumption adopted in the 1998 decision was likely to overstate the equity beta associated with the distributors' regulated activities. However, the Commission has also noted that a far lower proxy equity beta (0.55) would be derived if exclusive reliance were placed on the most recent market evidence. In forming its judgment that an assumed equity beta of 1 is appropriate, the Commission has sought to provide continuity between regulatory decisions and had regard to the long-term consequences of the Commission's decisions for the Victorian gas industry.

[247] Since the Draft Decision, one further company – AlintaGas – has had a sufficient trading history for an equity beta estimate to be obtained. The criteria used to select the comparable entities are discussed in Appendix C.

The difference between the Commission's assumption and those of the distributors reflects the Commission's view about the suitability of one of the comparable entities used by the distributors and the appropriateness of a technical adjustment to equity beta estimates (which the Commission had raised in earlier consultation papers and in the Draft Decision). The distributors also placed weight on the beta estimates that were undertaken over the period June 2000 to June 2001, even though more current estimates were available at the time they prepared their submissions, which suggested lower equity beta estimates.

Financing arrangements

The Commission has assumed a benchmark financing structure for the gas distributors, as it did in its 1998 decision. There are two interrelated components of this benchmark assumption namely, the assumed level of gearing and the assumed cost of debt finance.

The Commission has adopted an assumed gearing level of 60 per cent debt-to-assets. This is based upon observed gearing levels by comparable Australian businesses. This assumption is identical to that adopted in the 1998 decision, and is consistent with all of the distributors' proposals.

In order to derive a benchmark for the cost of debt, assumptions are required for the credit rating that would be consistent with the Commission's other assumptions, and for the term of debt that would be consistent with an optimal debt portfolio. The Commission has assumed a benchmark credit rating of BBB+ and a ten-year term for debt, which is consistent with the assumptions adopted in the Draft Decision. The Commission also remains of the view that these assumptions are likely to be conservative given the observed behaviour of comparable Australian firms.

Given these assumptions, the Commission has derived the benchmark cost of debt as the average of yields (in excess of the equivalent Commonwealth security) on this class of Australian corporate bonds over the same period that interest rates were sampled to derive the proxy real risk free rate. In the Draft Decision, the Commission used a data series provided by the Commonwealth Bank – CBASpectrum – as the source of the information on bond yields. As there are few Australian corporate bonds of this term and credit rating, the yields produced are inferred from the bonds of available terms and credit ratings. The Commission's subsequent investigations suggested that the predicted yields are close to the indicative pricing for corporate bond yields from other research houses, and so the Commission has again used the CBASpectrum service to derive the benchmark debt margin for the purposes of this Final Decision.

Applying this methodology has resulted in a higher assumption about the debt financing costs of an efficient distributor than in its 1998 decision, as well as in the Draft Decision. The change from the 1998 decision reflects the Commission's more considered view of the assumptions about the credit rating and term of debt that are appropriate for deriving a benchmark cost of debt. The Commission notes that adopting transparent assumptions about the credit rating and term of the benchmark debt portfolio, and using current market evidence on the cost of debt associated with such a portfolio, provides a methodology that is objective, reflects current market evidence, and can be replicated easily across decisions and industries. The change from the Draft Decision reflects this – the evidence suggests that margins on corporate bonds (in excess of the equivalent Commonwealth security) have increased since the Draft Decision, and this has been incorporated in the Final Decision.

The Commission has also retained its view that an allowance of 5 basis points in respect of benchmark non-margin establishment costs, as assumed in the Draft Decision, is appropriate.

Cost of raising equity

The Commission has also considered Multinet's proposal that it should include an allowance for the transactions cost associated with raising equity in the revenue benchmarks. The Commission has noted that the transaction costs for equity and debt differ. In particular, the former is perpetual once it is raised, whereas the latter has to be rolled-over periodically (with new fees paid). It has also noted that only new injections of equity imply transaction costs – investments from retained earnings or depreciation allowances do not give rise to transactions costs.

The Commission considers that any transaction costs associated with financing equity in the network that was in place on 1 January 1998 are reflected in the value assigned to those assets, and so the only issue is whether an efficient distributor would have required a new injection of equity in order to undertake capital expenditure since that time. The Commission has noted that the complete resolution of this issue would require a reasonably complex financial modelling exercise, in turn requiring a number of additional assumptions. That said, the Commission has noted that, as the regulatory values of the networks as at 1 January 1998 were based upon replacement cost (thus implying large depreciation allowances) and modest rates of growth have been experienced and forecast, it unlikely that an efficient firm would have required new equity injections to meet capital expenditure requirements over the first or second regulatory periods.

Accordingly, the Commission has not considered it appropriate to include an allowance in total revenue for the second access arrangement period for the transaction costs associated with raising equity.

3.6.2 Allowance for company taxation

Benchmark for the cost of tax

The Commission has confirmed its view in the Draft Decision that the allowance for company taxation should reflect an unbiased forecast of the taxation liabilities for an efficient company. It has also confirmed the view expressed in its earlier consultation papers and in the Draft Decision that the most appropriate means of deriving the allowance for company taxation is to make an explicit calculation of taxation liabilities, based on a transparent set of tax-related assumptions.

The Commission has considered at length the issue of whether it should calculate the taxation allowances based upon the depreciation allowances available under the tax law, or whether a notional (and slower) rate of depreciation should be assumed. A particular issue raised in submissions was how the Commonwealth Government's recently enacted effective life caps for gas infrastructure should be treated.

The Commission has concluded that there is no sound basis for not taking account of the depreciation rates permitted under the tax law when deriving a benchmark allowance for company taxation. Importantly, the Commission has also observed that such a treatment is also consistent with a public policy objective of encouraging extension of gas networks, and is not inconsistent with statements that the distributors should receive the cash flow benefits of the measures, if interpreted correctly.

Regarding the extension of gas networks, one factor that limits the areas where gas can be supplied economically is the need for gas to compete with alternative fuels, such as bottled gas. Accordingly, currently uneconomic projects can only become economic if there is a fall in the price at which customers can be supplied. The recent enactment of effective life caps for gas infrastructure provides one means by which there is scope for the delivered price of natural gas to fall – and hence its competitiveness against alternatives to improve.

Following the approach foreshadowed in its earlier consultation papers and applied in the Draft Decision, the Commission has adopted in this Final Decision simplifying assumptions for many of the tax-related inputs. Most of these assumptions are required for the assessment of reference tariffs regardless of how the taxation allowance is derived – these being: assessable revenue; operating expenditure; capital expenditure and interest deduction. For the only other inputs required – tax depreciation – while the Commission has been informed by the distributors' proposals and statements as to their actual taxation practices, the Commission has adopted its own industry-wide benchmark assumptions for many of the inputs, on the basis of its own independent professional tax advice. That said, the Commission has accepted a number of the distributors' comments on the assumptions it adopted in the Draft Decision, which have had the effect of raising the benchmark tax allowances.

The Commission's detailed analysis of the matters summarised above and of the assumptions it has adopted for that calculation, and its consideration of the distributors' comments on the assumptions adopted in the Draft Decision, are discussed in Appendix C.

Franking credits

A factor that is also relevant for the assumption about company taxation liabilities is that, under the system of dividend imputation, Australian shareholders are able to receive a credit for tax paid at the company level when determining their personal income tax. The standard practice amongst Australian regulators and finance practitioners is to treat this benefit as an offset to the particular entity's company taxation liability.

The assumed value of imputation (or franking) credits created is usually expressed as a proportion of their 'face value', with this proportion commonly denoted by gamma (γ). This approach implies that if a regulated entity were assumed to pay $X in company tax in a particular year, then the regulated entity would only require an allowance of $\$(1-\gamma).X$ for taxation. The remaining $\gamma.X$ would be provided directly to shareholders through the imputation system.[248]

In this Final Decision, the Commission has retained the assumption adopted in its 1998 decision and in the Draft Decision that a reasonable view of the market value of franking credits at the point of creation is approximately 50 per cent of their face value. The Commission notes that the value of franking credits remains a controversial issue amongst finance academics and practitioners. However, it has confirmed its view that the assumption it adopted in the 1998 review and in the Draft Decision is consistent with the objective market evidence.

In coming to this view, the Commission has also considered the question of the national identity it should assume for the equity participants in the industry. The Commission has confirmed the view it reached in the Draft Decision and which it has adopted in all previous decisions (including the 1998 decision) that the only practicable benchmark for the national identity of investors in the Victorian gas distributors is that of the average investor in Australian equities.[249]

In contrast, all of the distributors have argued that the Commission should adopt an assumption that franking credits are not valued in the market, with the principal argument being that the price setting (marginal) investor either in the economy as a whole or in these firms in particular is an international investor, who cannot use the credits. The Commission has noted that it considers this view to be inconsistent with the empirical evidence, particularly in light of its view that investors should be assumed to correspond to the average investor in Australian equities.

---

248 This interpretation of the gamma term holds regardless of whether the value of franking credits are reflected in the WACC or in the cash-flows.

249 More particularly, the assumption is that investors in the Victorian gas distributors correspond to the average investor in the Australian share market. As the Commission has noted previously, the average investor in the Australian share market is approximately 30 per cent foreign.

The Commission has also noted that the distributors' arguments that the presence of foreign investment implies that a zero gamma (and higher cost of capital) should be assumed only recognises the detriments suffered by foreign investors relative to domestic investors. While foreigner investors have less access to franking credits, they also have a number of benefits – in particular, by investing across a number of markets, a greater degree of diversification of risk can be achieved, and secondly, the systematic risk of Australian assets to foreigners is very low.[250] The Commission considers that these benefits to foreign investors are likely to more than offset the tax-related detriment through having less access to franking credits.

3.6.3 Excluded events

As noted above, while only the non-diversifiable portion of the risk affects an asset's cost of capital (ie. the return investors require on average, or the expected return), the Commission has acknowledged that a second issue is whether the price controls generate that expected return. In theory, this requires an assessment of whether all of the forecasts adopted in setting the price controls are unbiased as well as the net impact of all events not explicitly considered in setting price controls. However, an important matter is to understand the likely materiality of such events, having regard to the totality of the regulatory arrangements.

As noted in section 3.2, all of the distributors included an additional allowance in their operating expenditure to cover the expected cost associated with events that otherwise had not been considered in the assessment of their reference tariffs. These amounts were about $0.9 million per annum for Envestra and Multinet, and $0.73 million for TXU, and were taken from a report each of the distributors commissioned from Trowbridge Consulting/Deloitte Touche Tohmatsu. In addition, Multinet included an allowance to cover the 'fair value' of purchasing a one-way hedge against the adverse financial consequences associated with warmer than average weather over the next regulatory period. This fair value amounted to approximately $1.6 million per annum.

Expected cost of 'excluded events'

The Commission remains of the view that the Trowbridge Consulting/Deloitte Touche Tohmatsu reports provided a well-considered and thorough assessment of the likely adverse events that may affect the earnings associated with the Victorian distributors' regulated activities. It has also noted that, as well as informing the current regulatory process, the Commission would expect that the greater understanding of these matters would assist the distributors in the development of their own strategies to mitigate the likelihood, or to ameliorate the consequences, of such events. However, the extent to which the distributors bear the cost associated with excluded events depends, in large part, upon the features of the regulatory arrangements that are approved by the Commission. The Commission has confirmed the views it expressed in the Draft Decision that it considers the balance of evidence to suggest that the expected cost of these negative 'excluded events' to the distributors are unlikely to be material when considered in the context of the totality of these regulatory arrangements.

[250] As discussed in section C.8.2, the empirical evidence suggests that the betas of Australian activities are substantially lower when measured against a world share market than against the Australian share market.

However, the relevance of the material to the Commission is limited to whether recognising such events should lead to a materially different set of price controls for the distributors. Importantly, the relevance of such events needs to be considered in the context of the totality of the regulatory arrangements.

In particular, the Commission remains of the view that it is appropriate for the distributors to bear only a portion of the expenditure consequences associated with an ‘excluded event’, which is achieved by permitting capital expenditure in respect of such events to be included in the distributors’ capital bases, and for all expenditure to be considered in the efficiency carry-over. The Commission does not consider it practicable to differentiate between expenditure that arises from ‘excluded events’ and that which is a consequence of normal events, and does not consider there to be any ‘incentive’ arguments for distinguishing between these events. The Commission has also confirmed its view that it considers it desirable for the distributors to be substantially shielded from the risk associated with retailers defaulting, and has approved terms and conditions that have this effect.

The Commission has also considered the argument that a provision for self-insurance is necessary to ensure the distributors have the incentive to make an efficient selection between insurance and self-insurance. However, the Commission has not been convinced that the potential for a perverse incentive to over-insure is sufficiently large to warrant the application of a self-insurance premium, particularly as the distributors are subject to price cap regulation, and because insurance is not available for many events regardless of any perverse incentive. The Commission has also not been convinced that the provision of a self-insurance premium would be the best means of addressing such a perverse incentive if one was considered to exist. In particular, it has noted that the level of uncertainty associated with deriving a self-insurance allowance implies that the promise of such an allowance at future reviews is unlikely to generate a material change in the distributors’ insurance purchases.

The Commission has also noted that it considers it desirable, where possible, that risk be eliminated rather than compensated. For example, the Commission has facilitated a process with the Office of Gas Safety as part of the assessment of the distributors’ expenditure proposals to attempt to reduce the likelihood of a change in safety requirements during the regulatory period. It has also approved expanded change in tax pass-through clauses that would allow a pass-through of the cost associated with a change in mandated requirements. The Commission has also noted that it would expect prudent distributors to take actions to eliminate risks, like ‘key person risk’, particularly given the significant safety issues associated with gas distribution.

Lastly, the Commission also remains of the view that the conservative assumptions it has adopted elsewhere in this Final Decision would outweigh many times over the residual expected cost associated with these excluded events.

These matters are addressed in more detail in Appendix C.

Weather hedging

The Commission has also confirmed its Draft Decision to reject Multinet's proposed approach to include an allowance in relation to the cost of purchasing a one-way hedge against unfavourable weather events in its operating expenditure.

Multinet's proposal would result in it being able to avoid any financial consequences associated with adverse (warmer) weather, but continue to benefit financially from favourable (colder) weather. That is, Multinet's proposal adjusts only for the costs associated with the hedge – but none of the benefits. If an allowance were made for the costs associated with such a hedge, it would also be necessary to deduct an allowance to remove the benefit associated with the one-sided hedge. This would almost precisely offset the initial allowance. Given that the net effect of the two adjustments would imply no change to reference tariffs, the Commission considers that the more practicable response is to exclude such an allowance.

The Commission has also responded to some misunderstanding of its views on the role of hedging that were contained in submissions to the Draft Decision. In particular, the Commission has noted that it has acknowledged that variation in a firm's cash flow may impact on the level of debt that a firm may maintain and/or its cost of raising debt finance. However, it has emphasised that the important matter is to ensure that there is *consistency* between the level of hedging assumed and the benchmark financing arrangements adopted. The Commission considers the benchmark financing arrangements adopted in this Final Decision are consistent with an assumption that the distributors do not undertake significant hedging activities apart from standard interest rate risk management.

Regulatory risk

The Commission has also responded to a number of comments from the distributors about the level of uncertainty associated with regulatory decisions, a key concern being that the Commission had ignored this matter in its Draft Decision.

The Commission does not agree that it ignored the adverse effects of uncertainty associated with regulatory decision making in its Draft Decision, or in this Final Decision. Rather, it has endeavoured in its various decisions to provide as much certainty as possible and appropriate, regarding the future exercise of its discretion. Some of the measures the Commission has accepted or proposed itself to reduce regulatory uncertainty include.

- stranded asset risk and regulatory depreciation – the Commission has accepted a fixed principle not to seek to identify and remove stranded or partially stranded (redundant) assets, and has accepted (or offered) this protection for 30 years. This commitment not to strand assets is legally binding. The Commission has also invited the distributors to bring forward the recovery of capital if they consider that future developments may reduce their ability to recover their investments through regulated charges;

- prudence/efficiency tests – the Commission has not sought to judge the prudence or efficiency of capital or operating expenditure, but rather has inferred that well-designed incentives will deliver this result. That is, it has not exercised the power to disallow capital expenditures, and has put in place a framework of incentive regulation that should obviate the need to consider disallowances in the future;

- efficiency carryover – the Commission has approved detailed principles for calculating a carryover amount at the next review. These principles will be legally binding on the Commission at the next review;
- pricing – the Commission has approved a price control formula that provides the distributors with greater discretion over tariff setting;
- licence fees – the Commission has approved a price control formula that largely insulates the distributors from the uncertainty associated with licence fees, and also permits them to recover the foreshadowed increase for the financial year 2001-02;
- cost of capital – the Commission has made transparent the assumptions upon which the cost of debt is estimated and confirmed its previous practice of deriving the risk free rate with reference to objective market data;
- cost of tax – the Commission has approved a fixed principle ensuring that the method that has been used to derive a benchmark tax allowance continues to be used for the next 30 years. This commitment with respect to the cost of tax methodology is legally binding; and
- recovery of FRC costs – the Commission has approved a fixed principle that will ensure that costs approved under the FRC Order in Council that have been unrecovered at the end of the next regulatory period, or which relate to continuing activities, are taken into account in assessing reference tariffs at the next review. This commitment with respect to FRC costs is legally binding.

The Commission considers that the combined effect of these measures should reduce substantially the uncertainty associated with future regulatory decisions but notes that further refinement of the regulatory approach over time is inevitable and desirable in light of experience, additional information and innovation in the practice of regulation, but which needs to be weighed against the likely to benefit to all parties from stability. However, the Commission does not accept that it is inevitable that all such innovation will be to the detriment of the distributors, and indeed considers that many of the measures discussed above unambiguously will favour the distributors (as well as customers) over the long term.

3.6.4 The building block approach and working capital

The Commission has also addressed the question of the formula to calculate total revenue (total revenue formula),[251] and the related question of whether it would be appropriate to include an additional allowance in total revenue in respect of working capital.

[251] The Commission has used the term ‘building block’ approach to refer to the ‘cost of service’ methodology as set out in section 8.4 of the Gas Code. The Commission has noted previously that the Gas Code also uses the term ‘cost of service’ to refer to one of the forms of regulation described in section 8.3 of the Gas Code, and so has used the term ‘building block’ approach to avoid confusion. The terms benchmark revenue requirement, revenue benchmark, revenue requirement and target revenue are also used to refer to total revenue (as defined in section 8.4 of the Gas Code).

In this Final Decision, the Commission has considered the guidance provided by the Gas Code over the choice of the total revenue formula, including sections 8.1, 8.2, 8.4 and 2.24, and has confirmed that the formula it used in the Draft Decision best meets these requirements. The total revenue formula that has been adopted in this Final Decision (abstracting from taxation matters and inflation) is:

$$\text{Total Revenue}_i = \text{WACC x Average Asset Value}_i + \text{Depreciation}_i + \text{O\&M}_i$$

Given the decision to adopt this formula to calculate total revenue, the Commission has concluded that it would be inappropriate to provide an additional allowance in respect of working capital.

In addressing these interrelated issues, the Commission has observed that any total revenue formula can be expressed as a net present value calculation. It further noted that any net present value calculation can be shown to make implicit assumptions about the timing of cash flow within each year, which would inevitably reflect a simplification of the true timing of cash flow. The Commission has confirmed its view that a relevant factor when evaluating the potential formulae for calculating total revenue is whether the implicit assumptions about the timing of cash flow within each year provide a reasonable proxy for the true timing of that cash flow. An equivalent question is whether the reference tariffs provide a stream of cash flow with a net present value of zero,[252] taking into account the true timing of cash flow within each year. This is referred to as the 'net present value' rule below.[253]

A working capital requirement arises where operating costs are paid in advance of revenue receipts, creating a cost of financing those activities. The Commission has observed, therefore, that arguments for a working capital allowance are equivalent to arguing that the implicit timing assumptions *in relation to operating activities* may not reflect the true timing of that subset of cash flow within a given year, and so may ignore this financing cost.

However, the Commission has noted that it is inappropriate to analyse the accuracy of the implicit timing assumptions in a total revenue formula with respect to operating activities alone. The application of the 'net present value rule' discussed above would suggest that it is the net impact of differences between the assumed and true timing assumptions across all cash flow that is more relevant, which is an empirical matter. One implication of the 'net present value rule' is that an additional allowance in respect of working capital would not be required if the understatement of the financing cost associated with operating activities was offset by an overstatement of the financing cost of financing capital programs, having regard to the true timing of cash flow within each year. A second implication is that the answer of whether an allowance in respect of working capital is required will depend upon the specific total revenue formula that is adopted. The empirical method that the Commission has employed previously to test the accuracy of the timing assumptions implied by different total revenue formula is described in Appendix D.

252 The 'net present value' associated with the regulated activities will only be zero if the Commission's assumptions are unbiased forecasts of those inputs. As the Commission has adopted a conservative approach with respect to many of the inputs, the 'true' net present value associated with the income from the regulated activities would be expected to exceed zero.

253 The application of the 'net present value rule' implies discounting cash flow on a weekly or daily basis rather than on an annual basis.

Multinet has stated that it has applied the 'net present value' to the cash flow associated with its regulated activities and found there to be no material bias with respect to the calculation of financing costs considered across operating activities and capital programs.[254] In this Final Decision, the Commission has accepted Multinet's analysis with respect to the outcome of the net present value rule for the Victorian gas distributors.

In its responses to the Draft Decision, Envestra accepted that the 'net present value' rule discussed above is a relevant matter when assessing the appropriateness of the total revenue formula and the related issue of whether an allowance in respect of working capital is appropriate. However, it argued that the Commission has applied its own approach incorrectly. Envestra's submissions were supported by analysis by Dr Stephen Bishop.

The Commission has analysed the arguments presented by and on behalf of Envestra, and has not accepted the argument that it applied the 'net present value rule' incorrectly. The Commission's analysis of the material presented by Envestra is complex and is discussed at length in Appendix D. However, the intuition as to why the Commission considers it unlikely that total revenue formula would be weighted against the distributors is as follows. The within-year timing assumptions implied by the total revenue formula described above are that:

- half of the annual depreciation allowance is received and half of the annual capital expenditure is undertaken at the commencement of the year, with the remainder received or spent at the end of the year;
- the return on assets component of the revenue benchmark is received at the end of the year; and
- the timing of the share of revenue in respect of operating and maintenance expenditure is aligned with the timing of these costs.

The third of the above assumptions is likely to be biased against the distributors (and imply a working capital requirement). However, the second of the above assumptions is likely to favour the distributors because revenue is actually received progressively over each year. The 'return on assets' share of revenue accounts for about half of the revenue stream, and the error in the implicit timing assumption would be approximately six months. Therefore, the latter positive bias would be expected to more than offset the negative bias from omitting a working capital allowance.

As noted above, the implication of the 'net present value' rule was only one of the matters the Commission considered when forming a view about the most appropriate total revenue formula and the related question of whether a separate allowance in respect of working capital allowance should be provided. The Commission also considered detailed submissions from Envestra on the implications of sections 8.1, 8.4 and 2.24 of the Gas Code. The Commission's consideration of the requirements of the Gas Code and arguments presented in Envestra's submisisons with respect to this issue is set out in detail in Appendix D.

254 The Commission provided the distributors with the financial model that it had used to assess the accuracy of the timing assumptions in this total revenue formula for the specific circumstances of the electricity distributors. Multinet's assessment used the Commission's model.

3.7 Regulatory depreciation and redundant capital

3.7.1 Gas Code requirements

In addition to the objectives in section 8.1, the Gas Code specifies a number of specific principles to guide the depreciation allowance that is to be assumed in determining reference tariffs.[255] This includes principles that require the method to be consistent with the efficient growth of the market, reflect the economic lives of the assets or groups of assets employed (adjusted for changes in expected lives), and result in assets only being depreciated once.[256]

The Gas Code also permits a regulator to foreshadow that, at future reviews, it will reduce a regulated entity's regulatory asset base to remove the value associated with assets that are considered to have become either fully or partly redundant (for example, where there is a reduction in demand). However, if the regulator foreshadows such a policy, it is required to take into account the implications when determining the return required on the regulated assets, and the allowance for depreciation.[257]

3.7.2 Background and the distributors' proposals

In its consultation papers prior to the Draft Decision, the Commission considered the issues associated with regulatory depreciation and redundant capital together. This is because the Commission's decisions on both of these principles will affect the distributors' confidence as to whether they will be able to recover the value of their past investments.

In these consultation papers, the Commission expressed the view that there appeared to be substantial benefits to both customers and distributors from a policy that minimised the risk to distributors associated with recovering the regulatory value of their assets. Consistent with this approach, the Commission expressed the view that:

- with respect to regulatory depreciation (return of capital), distributors should have a degree of flexibility over the rate at which capital is returned, and in particular to take account of technological change, projected future demand and any other factors that may affect the (unregulated) market value of their assets in the future; and
- with respect to redundant capital, the Commission would choose not to preserve the flexibility to write-down the regulatory value of distributors' assets at a future regulatory review.

With respect to redundant capital, the Commission has considered the arguments that customers should not be charged for assets that are not used, and that threats to remove redundant assets may provide appropriate incentives for the distributors to undertake only efficient investment.

---

255 Section 8.33 of the Gas Code.
256 Sections 8.32-8.35 of the Gas Code.
257 Section 8.27 of the Gas Code.

Regarding the first of these arguments, the Commission noted that under a contrasting policy whereby distributors bear the consequences of asset stranding, the regulator would be obliged to provide distributors with compensation for the expected cost of accepting this liability. If the expected loss is quantified precisely, then prices will be expected to be unchanged on average compared to the Commission's proposed approach. However, if the compensation erred towards the upper end of the range of estimates, customers would be on average worse off compared to the Commission's proposed approach.

With respect to the second, the Commission has noted that the incentive arrangements described in section 3.8 of this Final Decision – whereby distributors effectively bear the cost of their expenditure decisions for between five and six years – is a far more targeted, and hence appropriate, incentive mechanism. In particular, the Commission noted that many of the events that may result in a gas distributor's assets becoming unused at some future time are outside of the distributors' control, and therefore not events that could be planned against.

Regarding regulatory depreciation, in their access arrangement proposals, all of the distributors advocated the continued use of straight-line depreciation (applied to an asset base that is indexed for inflation). The proposals noted a number of benefits of this method, including that it is consistent with a stable growth in demand, and that the allowance calculation is transparent and easily replicated. However, the distributors proposed that there be a lower rate of return of capital than implied by this method in order to meet their price path objectives for the next regulatory period, which implied a lower rate of return of capital than that which applied in the first regulatory period.[258]

Regarding redundant capital, each of the distributors adopted the Commission's proposal that the regulator should not retain the flexibility to identify and remove amounts in relation to redundant capital at the next review. In addition, all of the distributors proposed including a fixed principle that would preclude the removal of redundant capital for the 30 years from 1 January 2003 (in the case of Envestra) and at the next review (in the cases of TXU and Multinet).[259]

3.7.3 Draft Decision

Regarding regulatory depreciation, the Commission accepted the method of depreciation *advocated* by the distributors – which was straight-line depreciation on an inflation-indexed asset base, noting that this would imply a continuation of the method used in the first regulatory period.

---

258 Envestra, Access Arrangement Information, 2 April 2002, pp.46-47; Multinet, Access Arrangement Information, p.55; TXU did not state expressly that its reduction is to meet pricing objectives. However, the Commission assumed this to be the case in the Draft Decision, and TXU has not disagreed with this assumption.

259 Envestra, Access Arrangement, clause 7.1 (e); Multinet, Access Arrangement, clause 7.2 (a); TXU, Access Arrangement, clause 7.2 (a).

As noted above, each of the distributors has *actually used* a lower rate of depreciation when calculating their reference tariffs. However, as the Commission's decisions on other matters implied that this deferral of depreciation was no longer required to meet the distributors' pricing objectives, it replaced the distributors' proposals with a proxy for straight-line depreciation (that is, a higher rate of return of capital than that proposed by the distributors). With respect to Envestra, the Commission adopted the figures that it had provided elsewhere in its submission. For TXU and Multinet, the Commission assumed that the average rate of return of capital for 2002 would continue over the next regulatory period.

Regarding redundant capital, the Commission noted that the distributors had adopted its proposal.

3.7.4 Responses to Draft Decision

In response to the Draft Decision, Multinet provided its own calculation of straight-line depreciation of its capital base over the next regulatory period. However, it noted that a downward adjustment to the rate of return of capital is an appropriate means of taking account of a rise in costs, while also minimising the upward rate of change of prices.[260] Envestra submitted a revised calculation of straight-line depreciation consistent with its revised capital expenditure forecast.

TXU did not submit a revised calculation of straight-line depreciation to the approximation employed by the Commission in the Draft Decision.

3.7.5 Further analysis

The Commission confirms the view expressed in the Draft Decision and in its previous consultation papers that there are likely to be substantial benefits to both customers and distributors from a policy of minimising the risk to distributors associated with recovering the regulatory value of their assets. Consistent with this, the Commission remains of the view that it is appropriate to indicate in this Final Decision that, with the exception of adjusting for 'disposals', it has no current intention to seek to identify and remove redundant assets at future price reviews. The Commission's discussion of the distributors' proposed future adjustment for disposals is set out in section 5.1.

Regarding regulatory depreciation, the Commission has accepted the distributors' revised calculations of straight-line depreciation (for Envestra Victoria, Envestra Albury and Multinet) and adopted the estimates used by the Commission in the Draft Decision (for TXU) in assessing the distributors' reference tariffs.

260 Multinet, Response to the Draft Decision, pp.72-73.

However, the Commission notes that each of the distributors has expressed a preference for adjusting the straight-line regulatory depreciation allowances should such an adjustment be required to meet their desired pricing outcomes. While an adjustment would not appear warranted for Envestra and TXU, the price path determined for Multinet implies prices rising in real terms after 2003. The Commission would accept a proposal from Multinet to offset such a price rise through an adjustment to regulatory depreciation if Multinet considers this to be warranted.

The fixed principles dealing with redundant capital are discussed in section 5.1.

3.7.6 Final Decision

The regulatory depreciation allowances for the distributors for the next regulatory period are set out in table 3.28.

3.8 Efficiency carryover

This section sets out the Commission's Final Decision in relation to the incentive mechanism to be included in the distributors' Access Arrangements to apply to the carryover of efficiency gains made in the second access arrangement period to the third access arrangement period. Specifically, this section sets out the responses to the Commission's Draft Decision and the Commission's subsequent analysis in relation to the following issues:

- the appropriate carryover period;
- the treatment of negative carryovers;
- clarification of aspects of distributors' proposals;
- adjustment to the benchmarks in calculating the efficiency carryover amount; and
- the treatment of efficiency gains in the last year of the regulatory period.

In addition, this section sets out the Commission's Final Decision in relation to the efficiency carryover amount calculated for the 1998-2002 access arrangement period. This efficiency carryover amount has been incorporated into the required revenue for the second access arrangement period.

3.8.1 Gas Code requirements

Sections 8.44 to 8.46 of the Gas Code cover the use of incentive mechanisms. Section 8.44 states that:

> The Reference Tariff Policy should, wherever the Relevant Regulator considers appropriate, contain a mechanism (an Incentive Mechanism) that permits the Service Provider to retain all, or any share of, any returns to the Service Provider from the sale of the Reference Service:
>
> (a) during an Access Arrangement Period, that exceed the level of returns expected for that Access Arrangement Period; or
>
> (b) during a period (commencing at the start of an Access Arrangement and including two or more Access Arrangement Periods) approved by the Relevant Regulator, that exceed the level of returns expected for that period,
>
> particularly where the Relevant Regulator is of the view that the additional returns are attributable (at least in part), to the efforts of the Service Provider. Such additional returns may result, amongst other things, from lower Non-Capital Costs or greater sales of Services than forecast.

Section 8.46 sets out the objectives that should underpin the design of an incentive mechanism. The three objectives that pertain to cost-related efficiency gains are:

(b) to provide the Service Provider with an incentive to minimise the overall costs attributable to providing those Services, consistent with the safe and reliable provision of such Services;

(d) to provide the Service Provider with an incentive to undertake only prudent New Facilities Investment and to incur only prudent Non Capital Costs and for this incentive to be taken into account when determining the prudence of New Facilities Investment and Non Capital Costs for the purposes of sections 8.16 and 8.37; and

(e) to ensure that Users and Prospective Users gain from increased efficiency, innovation and volume of sales (but not necessarily in the Access Arrangement Period during which such increased efficiency, innovation of volume of sales occur.)

More generally, the Commission also has regard to the principles set out in sections 8.1, 8.2 and 2.24 of the Code.

The Gas Code provisions are relevant in assessing the efficiency carryover mechanism to apply from the second access arrangement period to the third access arrangement period, and in relation to the efficiency carryover amount to be calculated for the 1998-2002 access arrangement period.

3.8.2 Existing fixed principles

In addition, in assessing the carryover amount in relation to the 1998-2002 period, the Commission is also required to have regard to fixed principle 9.2(b)(5) in the Tariff Order. This fixed principle requires the regulator, in making a price determination in relation to the 2003-07 access arrangement period, to:

> ensure a fair sharing between a Tariffed Distributor and its Customers of the benefits achieved through efficiency gains if, in the initial regulatory period, the Tariffed Distributor has achieved efficiencies greater that the value implied by the value of XD, which is the X factor that applies to the Tariffed Distributor under the CPI-X formula in the initial regulatory period [..] and, in ensuring a fair sharing of the benefits, may have regard to the following matters without limitation:
>
> (A) the primary objective of ensuring such a fair sharing of benefits is to maintain a continuity of incentive to make efficiency gains throughout an access arrangement period;
>
> (B) the need to offer the Tariffed Distributor a continuous incentive to improve efficiencies both in operational matters and in capital investment; and
>
> (C) the desirability of rewarding the Tariffed Distributor for efficiency gains, especially where those gains arise from the management initiatives to increase the efficiency of the relevant business.

The above provision is not relevant to efficiency carryover mechanisms in respect of the second and subsequent periods.

3.8.3 Summary of Draft Decision

The Commission has previously set out the principles of its preferred approach to quantifying the reward for efficiency-improving initiatives to be carried over from one regulatory period to the next.[261] Each of the distributors incorporated most of the key features of the Commission's proposed efficiency carryover mechanism into their proposed Revisions for the second access arrangement period.

In its Draft Decision, the Commission re-affirmed that it considered the appropriate carryover period for efficiency gains to be five years, and that it should be able to exercise discretion in deciding whether to carryover after the year in which the gain was made any negative amount from one access arrangement period to the next. It also considered the appropriate adjustments to be made to the original benchmarks in calculating efficiency gains, and the treatment of efficiency gains in the last year of the regulatory period.

The conclusions in the Draft Decision were:

- Envestra was required to amend its proposed Revisions (for both Victoria and Albury) to allow the carryover of efficiency gains for a total of five (rather than ten) years after the year in which the gain was made;
- Envestra was required to clarify that, in carrying over an accrued negative amount from one year to the next in the second access arrangement period, the negative amount would be multiplied by the pre-tax WACC applying to Envestra for the third access arrangement period;
- Both Multinet and TXU were required to amend their proposed fixed principles to permit the Commission to exercise its discretion in choosing whether to apply any negative amounts from the second to the third access arrangement periods;
- Each of the distributors was required to insert a clause:
    - describing the mechanism for adjusting the expenditure benchmarks in the second access arrangement period to take account of growth in calculating the efficiency carryover amount for the third access arrangement period. A fixed expenditure amount per connection should be specified as part of this mechanism;
    - describing the mechanism for adjusting the expenditure benchmarks for the second access arrangement period to take account of changes in scope in calculating the efficiency carryover amount for the third access arrangement period; and
    - clarifying that the efficiency carryover amount will be calculated as the net amount of the efficiency gains (or losses) relating to capital and non-capital expenditure.
- Envestra was required to clarify that:

[261] Op. cit., Position Paper, pp.72-84. The model was also previously discussed in Consultation Paper No. 1, pp.96-102.

- the operating expenditure benchmark for the first year of the next regulatory period will be set with regard to actual operating expenditure in the penultimate year of the previous regulatory period and the assumed efficiency gain between the penultimate and final periods embodied in the operating expenditure benchmarks; and
- at the regulatory review for the fourth regulatory period there will be an adjustment to the regulatory asset base to take account of the difference between forecast and actual capital expenditure in the last year of the second regulatory period.

In relation to the efficiency carryover amount calculated for the 1998-2002 period, in the Draft Decision the Commission proposed that there should be no negative carryover from the first to the second access arrangement period. It also proposed not to adjust the original expenditure benchmarks in calculating the carryover amount. As a result, the carryover amounts determined by the Commission for the first access arrangement period were:

TABLE 3.30
DRAFT DECISION: EFFICIENCY CARRYOVER AMOUNT FOR 1998-2002 – ($ MILLION IN JULY 2001 PRICES)

	2003	2004	2005	2006	2007
Envestra Albury	-	-	-	-	-
Envestra Victoria	-	-	-	-	-
Multinet	2.9	2.4	7.8	3.0	-
TXU	-	-	-	-	-

3.8.4 Appropriate carryover period for gains made in 2003-07

In their submissions accompanying their proposed Revisions, both TXU and Multinet adopted a five-year carryover period for efficiency gains. Envestra adopted a longer carryover period of ten years.[262]

In the Draft Decision, the Commission expressed the view that a five-year carryover period should apply to all distributors and therefore required Envestra to amend its proposed Revisions to allow the carryover of efficiency gains (or losses) for a total of five years.[263]

262 Draft Decision, p.118.
263 ibid.

Responses to the Draft Decision

In response to the Draft Decision, Envestra maintained its position that the carryover period should be extended to ten years as opposed to five. Envestra proposed that this principle should apply to efficiency gains incurred in the first and second access arrangement periods. Its justification for the longer carryover period is that it would ensure that there is a greater incentive for distributors to achieve efficiency savings and that a 'fair sharing' of benefits between distributors and users is achieved, as Envestra maintains is required under the Tariff Order fixed principle 9.2(b)(5).[264]

Envestra disputed the Commission's view that the 30/70 split of efficiency gains between the business and customers which is implied by the 5 year carryover period is more efficient than a 50/50 split, since it relies on an assumption that a business' responsiveness in making efficiency gains decreases as the share of the benefits it retains increases. It also expressed the view that this is not a logical position for the Commission to adopt and that any increase in the sharing of benefits would provide distributors with a greater incentive to achieve efficiency savings.[265]

Envestra again expressed the view that the term 'fair' sharing of benefits should reasonably be interpreted to mean that any benefits from efficiency gains should be divided approximately equally between distributors and users. A 50/50 sharing that would result from a carryover period of ten years would therefore be considered more appropriate than the 30/70 sharing that would occur over a five year period. Envestra also quotes a view that the term 'fair', as used in business transactions, relates to living up to a previous commitment. In this context, Envestra stated that at the time the distribution businesses were purchased, the interpretation of 'fair sharing' made by the businesses did not contemplate anything significantly less than 50 per cent sharing of the benefits arising from efficiency gains.[266] Envestra also noted that during the electricity distribution price review, the electricity distribution businesses opposed the use of a 30/70 sharing ratio.

Multinet indicated that it is prepared to adopt the efficiency carryover mechanism as proposed by the Commission. However, it noted that it believed that incentives would be unduly diminished under the application of a 30/70 sharing ratio.[267] TXU made no reference in its response to the carryover period or sharing ratio.

Further analysis

In the Draft Decision, the Commission required Envestra to amend its proposed Revisions to ensure that the period for the carryover of efficiency gains (or losses) was five years following the year in which the gain (or loss) was made, rather than its proposed ten-year period. Both TXU and Multinet have adopted a five-year carryover period for efficiency gains, and so were not required to amend their Access Arrangements.

---

264 Envestra, Response to Draft Decision, p.12.
265 ibid.
266 ibid.
267 Multinet, Response to Draft Decision, p.76.

The Commission notes that, in relation to the incentive mechanism that is to apply from the second to the third access arrangement period, the relevant legislative requirements are those contained in sections 8.44 to 8.46 of the Gas Code. The Tariff Order fixed principles apply only in relation to the Commission's decision incorporating efficiency gains from the initial access arrangement period. The Tariff Order provisions do not apply in relation to the Commission's decision on the incentive mechanism that is to apply from the second to the third access arrangement period.

The term 'fair sharing' does not appear in the Gas Code provisions relating to the adoption of an incentive mechanism. 'Fair sharing' is only used in the Tariff Order fixed principles. Envestra's arguments related to the interpretation of the term 'fair sharing' are not therefore relevant in considering the incentive mechanism to apply from the second access arrangement period, since, as noted above, the Tariff Order fixed principles do not apply to this decision.

Section 8.46 of the Gas Code refers to the need to provide the Service Provider with an incentive to minimise the overall cost of producing the services and to undertake only prudent capital and non-capital expenditure, whilst ensuring that users and prospective users gain from increased efficiency, innovation and volume of sales. The Commission considers that the five-year carryover period does provide an incentive for the service provider to reduce costs, whilst at the same time ensuring that efficiency gains are passed through to customers without undue delay. There is nothing in section 8.46 that determines the balance between the service provider and users in terms of how efficiency gains should be shared. The concept of 'fair sharing' is therefore not relevant to meeting the requirements of the Code.

The five-year carryover period under the Commission's efficiency sharing mechanism implies a 30:70 sharing ratio of efficiency gains, between the distributors and customers.[268] The Commission considers this sharing ratio to be reasonable in the light of the Code requirements. Specifically, there is nothing in the Code that would require a 50:50 sharing of gains, or the retention of benefit for ten years.[269]

The Commission's Final Decision is that Envestra is required to amend its proposed Revisions (for both Victoria and Albury) to allow the carryover of efficiency gains (or losses) for a total of five (rather than ten) years after the year in which the gain is made.

---

[268] This ratio has been calculated on the basis of the NPV of a five-year retention of a given gain, G, divided by the NPV of an infinitely retained gain, G. The calculation assumes a real discount rate of 7.5 per cent.

[269] Envestra expressed the view that the Commission's implicit assumption that the distributors' responsiveness to make efficiency gains decreases as the share of the benefits it retains increases was 'illogical'. Diminishing returns does not mean that the effort made by the distributor to achieve efficiency gains does not increase as the share of the gains it returns increases. Rather, it means that effort increases *less than proportionally* with the increased share retained. Envestra does not provide any evidence in support of its argument that responsiveness will increase *more than proportionally* with an increase in the share retained.

3.8.5 Treatment of negative carryovers

In their original submissions accompanying their proposed Revisions, Multinet and TXU both proposed that negative efficiency carryover amounts should not be carried over from the second to the third access arrangement period. In contrast, Envestra proposed that the Commission should consider the distributors' submissions in relation to negative carryover amounts and exercise its discretion in deciding whether such amounts should be carried over from one access period to the next.[270]

In the Draft Decision, the Commission expressed the view that it would be appropriate for it to have such discretion in order to maintain the incentive for distributors to make efficiency savings in the final years of an access arrangement period. Accordingly, it required Multinet and TXU to amend their proposed fixed principles to permit the Commission to exercise its discretion in choosing whether to apply any negative amounts from the second to the third access arrangement periods.[271]

Envestra also proposed that where the efficiency carryover amount is less than zero in any one year within an access arrangement period, it should be set to zero for that year and carried forward to be offset against positive gains in future years. The Commission accepted this proposal as being consistent with its model, but required Envestra to amend its proposed Revisions to clarify that any negative efficiency amount deferred between years in this way would be multiplied by the pre-tax WACC applying in the next regulatory period.[272]

Responses to the Draft Decision

All of the distributors proposed that there should be no carryover of a negative efficiency carryover amount from the second to the third access arrangement period. For Envestra, this represents a change from its earlier proposed Revisions, which included clauses to allow the Commission discretion in determining the appropriate treatment of any negative carryover amount accrued at the end of an access arrangement period (with the exception of the first access arrangement period).[273] Envestra has now proposed to delete these clauses and replace them with a clause that states that 'there will be no negative carryovers from one access arrangement period to the next.'

270 Draft Decision, p.115.
271 ibid, p.124.
272 ibid, p.123.
273 Envestra, Access Arrangement Part B, Reference Tariff Policy and Reference Tariffs, Clauses 7.2(c)(3) and (4).

Each of the distributors noted that the language of section 8.44 of the Gas Code refers to efficiency gains in positive terms only, with no reference made to efficiency losses.[274] They therefore contend that the Gas Code allows only for the carrying over of positive efficiency amounts. Both Multinet and Envestra noted that they have received legal opinions on this matter supporting this interpretation. Envestra's decision to amend its Reference Tariff Policy to exclude negative carryovers between access arrangement periods is a consequence of the legal advice it received.[275]

Both TXU and Multinet commented that distributors are already penalised if they spend in excess of the benchmarks, as they are unable to recover such excess costs.[276] TXU stated that a distributor would effectively be penalised twice if the negative amount were to be carried over into the next access arrangement period.

Multinet noted that given the incentive properties of the gas regime, one could infer that the actual costs incurred by distributors reflect efficient costs. It also commented that, in considering the appropriateness of carrying over negative amounts from the first to the second access arrangement period, the Commission regarded the inability of a distributor to meet its benchmark level of expenditure as a reason for not penalising the company. It stated that it concurs with the general principle implied by the Commission's decision in relation to the first access arrangement period, and considers this as support for not carrying over negative carryovers in future access arrangement periods also.[277]

Both TXU and Multinet also considered that the financial viability of a distribution business could be influenced by the carryover of a negative amount, given that the adjusted revenue stream would not be great enough to cover what the Commission had determined to be the efficient cost of delivering the reference service.[278] Multinet noted that such an outcome would be inconsistent with both the Gas Code and the objectives of the Gas Industry Act.[279]

TXU noted that the incentive for distributors to improve efficiency would be reduced if negative amounts were carried over between access arrangement periods, as they would be deducted from any efficiency gains made in subsequent years.[280] Such gains would therefore be partially excluded from future efficiency carryovers. It also expressed the view that the threat of having a negative carryover was not necessary for distributors to continue to have an incentive to make efficiency savings in the last years of an access arrangement period,[281] and that, if there is an efficiency loss in one regulatory period, this is of no relevance in the next regulatory period.[282]

274 TXU, Response to Draft Decision, 7 August 2002], p.10; Multinet, Response to Draft Decision, 7 August 2002, p.78; Envestra, Response to Draft Decision, 9 August 2002, p.13.
275 Envestra, Response to Draft Decision, 9 August 2002, p.13.
276 TXU, Response to Draft Decision, p.10; Multinet , Response to Draft Decision, p.79.
277 Multinet, Response to Draft Decision, p.79.
278 TXU, Response to Draft Decision, p.10; Multinet , Response to Draft Decision, p.78.
279 Multinet, Response to Draft Decision, p.78.
280 TXU, Response to Draft Decision, p.10.
281 ibid, p.18.
282 ibid, p.11.

Further analysis

The Tariff Order fixed principles apply only in relation to the Commission's decision incorporating efficiency gains from the initial Access Arrangement Period. The Tariff Order provisions do not apply in relation to the Commission's decision on the incentive mechanism that is to apply from the second to the third access arrangement period.

The Commission has resolved not to require negative carry-overs from the first access arrangement period to the second access arrangement period and therefore it is unnecessary to consider whether or not the Tariff Order permits negative carryovers between periods

The Commission notes that, in relation to the incentive mechanism that is to apply from the second to the third access arrangement period, the relevant legislative requirements are those contained in section 8.44 to 8.46 of the Gas Code.

There are two distinct aspects to the consideration of negative efficiency carryovers.

First is the principle that expenditure in excess of benchmarks (ie. an efficiency loss) should be carried over for five years following the year in which the loss is incurred, in the same way that expenditure below the benchmark level (ie. an efficiency benefit) is carried over for five years. This is the principle of the symmetric treatment of efficiency gains and losses. None of the distributors have opposed such symmetric treatment.

Where the distributor makes efficiency gains and efficiency losses over the same period, the interaction of the two implied amounts which arise under the efficiency carryover mechanism as a result, will determine whether, in the next access arrangement period, the total efficiency carryover amount calculated for that period (ie. the net present value of the efficiency carryover amounts for each year during that period) is positive or negative. The treatment of an overall negative efficiency carryover amount applying to the whole period is the second aspect of 'negative carryovers'. The distributors have each argued that any negative efficiency carryover amount that is calculated for the period as a whole should not be carried over from one period to the next.

The Commission notes that each of the distributors have put forward the view that the Gas Code at section 8.44 only permits the carry forward of positive efficiency gains from one access arrangement period to the next. Indeed, this interpretation has been instrumental in Envestra changing the position it originally put forward in its proposed Revisions that the Commission should be able to exercise discretion in deciding how any accrued negative amount should be carried over between one access arrangement period and the next.

Section 8.44 of the Gas Code was originally drafted as follows:

> The Reference Tariff Policy should, wherever the Relevant Regulator considers appropriate, contain a mechanism that permits the Service Provider to retain all, or a share of, any returns to the Service Provider from the sale of a Reference Service during an Access Arrangement Period (an Incentive Mechanism), particularly where

> the additional returns are attributable (at least in part) to the efforts of the Service Provider. Such additional returns may result, amongst other things, from lower Non Capital Costs or greater sales of Service than forecast.

This drafting is essentially retained in the current section 8.44(a).

Subsequent to the initial promulgation of the Gas Code, there was a concern that:

> The Code in its current form does not provide an unambiguous authority for regulators to use across-period incentive mechanisms. In particular, the definition of 'Total Revenue' under the three methodologies in section 8.4 does not contemplate inclusion of a "Benefit to the Service Provider from Efficiency Gains in the Previous Period(s)" as required for the use of across-period incentive mechanisms.[283]

The Gas Code as it was then did not fit well with the following policy objectives:

> If prices were immediately re-set at cost at the commencement of the subsequent access arrangement period, then the additional <u>(or lower)</u> profit to the service provider associated with these events would cease immediately from that time forward. In this case, *prima facie*, toward the end of the access arrangement period service providers have an incentive to defer initiatives designed to develop market demand, reduce costs and increase efficiency. This is because the service provider would only retain the benefit associated with an initiative until the end of the current access arrangement period.
>
> ...
>
> First, in principle, the arguments for permitting a carry-over of benefits only apply where the additional <u>(or lower)</u> profits result from the efforts of management – that is, are controllable. Where greater <u>(or lower)</u> profits than forecast result from purely exogenous events, there is no justification for continuing this benefit <u>(or cost)</u> into the next regulatory period. (emphasis added which highlights the intention to permit negative carryovers)[284]

As a result, two versions of a new clause 8.44 were proposed – Option A and Option B. These two options were essentially in the same terms except that Option B limited the extended period over which the relevant regulator could operate an efficiency mechanism to 10 years. Ultimately the participating jurisdictions agreed to adopt Option A, which is the current version of section 8.44:[285]

> The Reference Tariff should, wherever the Relevant Regulator considers it appropriate, contain a mechanism (an Incentive Mechanism) that permits the Service Provider to retain all, or any share of, any returns to the Service Provider from the sale of the Reference Service:
>
> (a) during an Access Arrangement Period, that exceed the level of returns expected for that Access Arrangement Period; or

---

[283] Natural Gas Pipeline Advisory Committee, "Information Memorandum Proposed Amendment to the National Third Party Access Code for Natural Gas Pipeline Systems" June 2000, p11

[284] ibid, p.9 and 10

[285] ibid, p.12

(b) during a period (commencing at the start of an Access Arrangement and including two or more Access Arrangement Periods) approved by the Relevant Regulator, that exceed the level of returns expected for that period,

particularly where the Relevant Regulator is of the view that the additional returns are attributable (at least in part), to the efforts of the Service Provider. Such additional returns may result, amongst other things, from lower Non Capital Costs or greater sales of Services than forecast."

On that basis, the Commission rejects the distributors' interpretation of section 8.44.

In the Draft Decision, the Commission expressed the view that it wished to be able to exercise discretion in determining the appropriate treatment of any negative carryover amount, having regard to the specific circumstances in which the negative amount has arisen.

The Commission considers that the ability to exercise discretion in relation to the treatment of a negative carryover would provide an incentive for the distributor not to defer making efficiency savings in the last year of a regulatory period, in the face of efficiency losses in earlier years in the period. The incentive to defer efficiency gains would arise because, if the distributor were to make an efficiency gain in the last years of the period, then that gain would go towards offsetting the negative amounts already accrued in determining the efficiency carryover for the next period. However, if the distributor knew that the negative amount was going to be 'wiped clean' at the end of the next access arrangement period, then it would have an incentive to hold-over the action leading to the efficiency gain until the first year of the new period.

The Commission notes TXU and Multinet's concerns that the carryover of a negative amount between the second access arrangement period and the third may be contrary to ensuring the financial viability of the distributors. As the Commission has previously noted in its Draft Decision, in deciding on the appropriate treatment of a negative carryover it would need to have regard to the principles set out in the Gas Code, including those in section 2.24 and in section 8.1.[286] These principles include the need to take into account the service provider's legitimate business interests. The ability of the Commission to exercise discretion is therefore limited to an extent by the requirements of the Gas Code, and the Commission would take these requirements into account in making any future decision on the treatment of a negative carryover amount.

---

286 Draft Decision, p.124.

TXU argued that carrying over a negative efficiency amount from one access arrangement period to the next (ie. from the third access arrangement period to the fourth) may *dampen* incentives for the distributor to make efficiency gains in the next period, since any such gains would be offset by the negative amount carried over. The Commission agrees with TXU's point. It is precisely for this reason that the Commission does not view an *automatic* carryover of any accrued negative amount as appropriate. Rather, the Commission's proposal is that it should have discretion to determine the most appropriate means of addressing a negative carryover, which may be to 'wipe the slate clean', to adjust the benchmarks for the next access arrangement period, or to carry the negative amount over, in full or in part. In exercising such discretion, as noted above, the Commission will have regard to the requirements of the Gas Code (as noted above) and to the impact on the distributors' incentives.

In relation to the other arguments presented by the distributors against the carrying over of any negative efficiency amount, the Commission notes that carrying over a positive efficiency gain could be viewed as rewarding the distributor twice, once in the year in which the gain is achieved, and then later via the efficiency carryover mechanism. Likewise, the argument that, if there is an efficiency loss in one regulatory period, this is of no relevance in the next regulatory period could also be applied in respect of efficiency gains.

In summary, the Commission remains of the view that it is appropriate for it to have discretion in determining the treatment of any accrued negative carryover amount at the end of future access arrangement periods. However, the Commission notes that such discretion will be exercised within the constraints of the objectives set out in the Gas Code.

The Commission's Final Decision is that Multinet and TXU should amend their proposed Revisions to permit the Commission to exercise this discretion. The Commission requires Envestra to reinstate clauses 7.2(c)(3) and (4) in its proposed Revisions.

The Commission notes that TXU and Multinet both refer to '*a* net negative efficiency carryover' (emphasis added) in the drafting of their Revisions. This reference is potentially ambiguous, given that carryover amounts will be calculated for each year of the second regulatory period. A negative carryover amount in one year can be offset by a positive carryover amount in another year, to give an overall positive carryover in net present value terms from the second access arrangement period to the third. As a result, TXU and Multinet are required to amend their Revisions to explicitly refer to 'a net negative carryover amount (in net present value terms, calculated at the pre-tax WACC applicable to the third access arrangement period)'.

Envestra has proposed that, where the efficiency carryover mechanism implies that the amount to be added to required revenue in any one year would be negative, that the amount added to required revenue in that year be set to zero, and the negative amount accrued and added to the carryover amount calculated for the following year.[287] In its Draft Decision, the Commission accepted Envestra's proposed approach to accruing negative amounts, but required Envestra to clarify that the pre-tax WACC applying for the third access arrangement period should be applied to any accrued negative amount. Envestra did not discuss or incorporate this amendment in its responding submission. Envestra is again required to clarify that the pre-tax WACC applying for the third access arrangement period should be applied in accruing any negative amount.

3.8.6 Clarification of aspects of the distributors' proposals

Each of the distributors indicated that they had sought to incorporate the key features of the Commission's proposed efficiency carryover model in their proposed Revisions to apply in the second access arrangement period.[288]

In its Draft Decision, the Commission required each of the distributors to incorporate clauses into their proposed Revisions to clarify certain aspects of their carryover arrangements.[289]

Responses to the Draft Decision

Multinet and Envestra confirmed that they have adopted a model whereby the efficiency carryover is calculated as the net amount of the efficiency gains (or losses) relating to operating and capital expenditure.[290] TXU earlier confirmed that this was also its intention.[291]

3.8.7 Adjusting the benchmarks

All of the distributors proposed in their Revisions that the calculation of efficiency gains for the second access arrangement period should take into account any differences between forecast and outturn growth and any changes in the scope of their obligations.[292]

---

287 In this way, a negative efficiency carryover amount in one year would offset any positive amount calculated in a subsequent year. In the event that there were insufficient positive gains in any of the remaining years in the regulatory period to fully offset this negative amount, then an 'accrued negative amount' would in principle remain at the end of the third regulatory period.

288 Draft Decision, p.113.

289 ibid, p.117.

290 Multinet, Response to Draft Decision, p.76; Envestra, Response to Draft Decision, p.14. Multinet does not explicitly include a reference to efficiency losses in its definition.

291 Email from P.Murphy (TXU) to N. Southerm (ESC), 9 May 2002.

292 Draft Decision, p.114. Both TXU and Multinet proposed an adjustment to benchmarks to account for such changes whilst Envestra proposed to adjust actual outturn numbers.

In the Draft Decision, the Commission expressed the view that it would be appropriate to adjust the benchmarks at the end of the regulatory period in calculating the efficiency carryover, in order to take account of changes in growth and the scope of the distributors' obligations.[293] However, the Commission noted that none of the distributors had disclosed the mechanism by which the expenditure benchmarks would be adjusted. The Commission also noted the apparent discrepancy in the proposed capital and operating costs per connection figures put forward by the distributors.

In assessing the issue, the Commission recommended that each of the distributors submit information in relation to changes in scope as part of their Access Arrangement Information at the time of the next review. The Commission also proposed that benchmarks be adjusted on the basis of the difference between the forecast and actual number of connections multiplied by a pre-established operating and capital expenditure per connection figure.

Responses to Draft Decision

With regard to changes in scope, Multinet and Envestra both agreed with the Commission's proposal to allow distributors to submit information relating to changes in scope at the time of the next review.[294] TXU noted that the proposed mechanism for adjusting benchmarks to take account of changes in scope needed further consideration.[295]

With regard to changing the benchmarks to reflect differences between forecast and outturn growth, Envestra distinguished between capital expenditure that is incurred due to changes in direct customer expenditure and that which is incurred as a result of general growth related purposes. In particular, it expressed the view that adjustments to capital expenditure benchmarks should only reflect changes in direct customer expenditure.[296] Envestra submitted a value of $1 400 as the average unit rate per new connection that would be appropriate for adjusting the 2003-07 capital expenditure benchmarks.[297]

Envestra noted that changes to operating costs due to differences between forecast and outturn growth are likely to be small within the regulatory period. Envestra noted that the figure of $11 per customer as proposed by TXU is not unreasonable. Envestra was therefore prepared to adopt this figure for the purpose of adjusting the operating cost benchmark for growth.[298]

293 ibid, pp.119-120.
294 Multinet, Response to Draft Decision, p.77; Envestra, Response to Draft Decision, p.14.
295 TXU, Response to Draft Decision, p.19.
296 Envestra, Response to Draft Decision, p.13.
297 Envestra, Albury & Victorian Access Arrangement, Summary Submission, 12 September 2002, p.11.
298 Envestra, Response to Draft Decision, p.13.

TXU sought to clarify its proposed capital expenditure cost of $1 776 per unanticipated customer for the second access arrangement period as outlined in the Draft Decision. In calculating the proposed adjustment, TXU had only included the cost of smaller customer connections, as the company had experienced higher growth in this customer segment over the period 1998-2002. TXU noted that the overall average cost per connection, which includes both small and large customers, is $1 918.[299]

Multinet agreed with the Commission's general approach to adjusting expenditure benchmarks for unanticipated growth. However, it considered that a more appropriate measure to be used to adjust benchmarks would be the average *actual* capital cost per new connection over the regulatory period as opposed to a pre-established estimate of expenditure per connection.[300] The rationale put forward for using this unit cost measure is that it is consistent with the Commission's inference that a distributor's actual expenditure reflects efficient costs. Multinet proposed that the method for calculating average costs could be specified in advance within the Access Arrangements and the data used for calculating average cost submitted over the access arrangement period to avoid any concerns regarding data integrity.

Multinet also noted that in principle, an adjustment should be made to allow for the impact of incremental changes in operating costs associated with the difference between forecast and actual connections. Multinet stated that it was not in a position to provide a robust estimate of the incremental cost per customer, although it noted that such an estimate had already been provided by TXU.[301]

The Energy Users Coalition of Victoria expressed the view that the Commission's efficiency carryover mechanism would be more likely to deliver consumer benefits from part efficiency gains if it were to undertake rigorous scrutiny of past and forecast operating expenditure and capital expenditure costs.[302]

Further analysis

In its Draft Decision, the Commission required the distributors to amend their proposed Revisions to describe the mechanisms for adjusting the expenditure benchmarks for the second access arrangement period to take account of growth and changes in scope in calculating the efficiency carryover amount.

In relation to adjustment for changes in scope, the Commission notes that Envestra and Multinet have both agreed with the Commission's proposed mechanism. TXU has not explicitly agreed, but has not put forward either objections or an alternative proposal. As a result, the Commission continues to be of the view that distributors should include a mechanism in their Access Arrangements to describe the basis for adjusting the benchmarks in the second access arrangement period to account for changes in scope.

---

299 TXU, Response to Draft Decision, p.11.

300 Multinet, Response to Draft Decision, p.77.

301 Multinet, Response to Draft Decision, p.77.

302 Energy Users Coalition of Victoria, Submission on the Essential Services Commission's Draft Decision, 29 August 2002, p. 10.

In relation to adjusting the benchmarks to take into account changes in growth, each of the distributors supported the Commission's general proposed approach of adjusting the benchmarks on the basis of the difference between forecast and outturn connections and a measure of capital and operating expenditure costs per connection.

All distributors have agreed that the impact on operating expenditure of an additional connection is 'small'. TXU provided an estimate of $11 per connection, which the other distributors have noted that they would be willing to accept. The Commission is willing to accept that the $11 per connection figure is an appropriate benchmark to use for adjusting the operating benchmarks to reflect differences between actual and outturn growth for the second access arrangement period.

In relation to capital expenditure per connection, Multinet has proposed that the adjustment be carried out on the basis of actual cost data for the second access arrangement period, once this is known. The Commission has concerns with such an approach, since it would provide a lesser incentive to ensure that expenditure in relation to new connections is efficient. The Commission considers that the impact on incentives would be stronger if the amount of additional expenditure allowed to reflect growth were pre-specified beforehand.

As a result, the Commission has adopted the benchmark direct unit rates for new connections, plus an allowance of 10 per cent for overheads. The analysis of the benchmarks for capital expenditure are in section 3.4**.**

The Commission's Final Decision is that the connection forecasts, together with the capital and operating expenditure per connection benchmarks shown in table 3.31 should be used to calculate any adjustment of the 2003-07 benchmarks, in calculating the efficiency carryover amount for the second access arrangement period.

TABLE 3.31
FINAL DECISION: BENCHMARK ADJUSTMENTS FOR GROWTH

	Number of new connections					Capital expenditure per connection ($)	Operating expenditure per connection ($)
	2003	2004	2005	2006	2007		
Envestra Victoria	8 500	8 400	8 400	8 400	8 400	1 273	11
Envestra Albury	299	170	244	272	221	1 273	11
Multinet	13 961	-9 244	9 126	7 609	6 819	1 334	11
TXU	14 618	13 359	13 393	13 993	12 740	1 478	11

The distributors are required to amend their proposed Revisions to include reference to the adjustment mechanism, including specification of the cost benchmarks and connection projections to be used.

3.8.8 Treatment of efficiency gains in the last year of the regulatory period

Given that information on actual expenditure for the last year of the regulatory period will not be available at the time at which the Commission will calculate the efficiency carryover amount, an assumption regarding expenditure (and therefore efficiency gains) needs to be made in the final year of the access arrangement period.

Both Multinet and TXU have adopted the approach previously proposed by the Commission.

In relation to operating expenditure, operating expenditure in the final year will be assumed to be equal to actual expenditure in the penultimate year, multiplied by the efficiency gain embodied in the operating expenditure benchmarks between the penultimate and final year of the period. The operating expenditure benchmark for the first year of the third access arrangement period will then be set on the basis of the assumed value for the last year of the second access arrangement period. To the extent that the distributor makes an efficiency gain in the final year of the regulatory period in excess of that assumed by the benchmarks (ie. actual operating expenditure is below the assumed level), then they will benefit by having actual expenditure below the assumed level against which the benchmark for the next regulatory period have been set.

In relation to capital expenditure, the capital base will be rolled forward on the basis of the benchmark capital expenditure for the last year in the second regulatory period, in order to establish the opening capital base for the first year of the third access arrangement period. To the extent that the distributor achieves capital savings in the last year, it will therefore benefit from receiving a return in the third access period on an assumed capital base that is higher than its actual capital base. There will then be a subsequent adjustment to the asset base at the start of the fourth access arrangement period, to take into account any difference between actual and benchmark capital expenditure in the last year of the second access arrangement period. This ensures that the distributor only benefits from its efficiency saving for the five years following the year in which the saving was made, rather than in perpetuity.[303]

The Commission considers that the approach described above provides distributors with an equivalent incentive to make efficiency gains in the final year of the regulatory period.

Envestra proposed a similar approach in its Revisions, but was more definitive in saying that the operating expenditure benchmark for the first year of the third access arrangement period would be set equal to the actual value of operating expenditure in the penultimate year of the second access arrangement period. In addition, it did not include any mechanism by which the regulatory asset base would eventually be adjusted to take account of efficiency gains (or losses) in the final year of the second regulatory period.[304]

---

303 Draft Decision, pp.115-116.
304 ibid, p.116.

In its Draft Decision, the Commission agreed with TXU and Multinet's proposed approach but required Envestra to amend its proposed Revisions to clarify that future operating expenditure benchmarks would take account of the assumed efficiency gain achieved between the penultimate and final year of the regulatory period, embodied in the operating expenditure benchmarks. It also required Envestra to clarify that at the regulatory review for the fourth regulatory period there will be an adjustment to the regulatory asset base to take account of the difference between forecast and actual capital expenditure in the last year of the second access arrangement period.[305]

Responses to Draft Decision

In response to the Draft Decision, Envestra agreed to clarify the manner in which benchmarks for future regulatory periods will be determined in its Reference Tariff Policy. In relation to capital expenditure, Envestra agreed to an approach whereby the capital base at the end of the final year of an access arrangement period could be adjusted to take account of the actual capital expenditure incurred in the last year of the previous access arrangement period.[306]

TXU disagreed with the Commission's Draft Decision assessment that distributors would receive an equivalent benefit from having the efficiency carryover amount set to zero in the final year of an access period, as the impact of the efficiency gain would be reflected in the subsequent year's expenditure benchmarks. In particular, it disagreed with this statement given the 1 per cent productivity factor applied to operating cost benchmarks in the next regulatory period, which it said would reduce the efficiency gain that is incorporated into the benchmarks for the next access arrangement period. TXU expressed the view that the method proposed by the Commission applies forecast productivity improvements to past results and is therefore a clawback of benefits ultimately resulting in a sharing ratio where less than 30 per cent is attributed to the service provider.[307]

Further analysis

The Commission notes that Envestra has agreed to amend its proposed Revisions to clarify the assumptions that will be made in determining the expenditure benchmarks for the next regulatory period, and that these assumptions are in line with the Commission's Draft Decision. However, Envestra's proposed amendment in relation to the adjustment of the capital base in future access arrangement periods is that the capital base 'can be adjusted to reflect the actual amount of expenditure included in the final year of the previous Access Arrangement Period'.[308] In this context, the Commission considers that the term 'will' is more appropriate than 'can' and provides greater clarity and certainty in relation to the approach,

305 ibid, p.121.
306 Envestra, Response to Draft Decision, p.14.
307 TXU, Response to Draft Decision, p.11.
308 Envestra, Response to Draft Decision, p.14.

TXU has expressed the view that the application of a productivity factor in determining the operating expenditure benchmark for the first year of the new access arrangement period reduces the efficiency gains embodied in the expenditure benchmarks for the next period, and that this is a ‘clawback’ of benefits. The Commission does not agree with this view. The Commission’s position is that there is scope for a reduction in operating expenditure between 2002 and 2003. To the extent that a distributor makes an efficiency gain in 2003, its actual expenditure will be less than that assumed by the Commission in establishing the 2003 benchmark and, if it achieves the productivity growth between 2002 and 2003 assumed by the Commission, it will continue to enjoy the benefit of that efficiency gain.

The Commission’s Final Decision is to accept the approach proposed by TXU and Multinet for the treatment of efficiency gains in the final year of the regulatory period. Envestra is required to amend its approach to clarify the assumptions that will be made in determining the expenditure benchmarks for the next regulatory period.

3.8.9 Carryover for the 1998-2002 period

In relation to the efficiency carryover amount calculated for the 1998-2002 period, the Commission’s Draft Decision was that the approach to apply for the second access arrangement period should also apply to the first, but that there should be no negative carryover from the first access arrangement period to the second. The Commission also did not adjust the original expenditure benchmarks in calculating the carryover amount.

The Commission noted in its Draft Decision that the expenditure benchmarks in the initial access arrangement period have proved to be relatively hard to meet, largely because of the lack of available information at the time at which the benchmarks were set. As a result, the Commission viewed the inability of two of the three distributors to meet the expenditure benchmarks for 1998-2002 as evidence that the benchmark figures were below the level of expenditure that has proved necessary.[309] As a result, in the Draft Decision the Commission proposed that where the application of the efficiency carryover mechanism would otherwise result in a negative amount for a distributor, then the carryover amount should be set to zero.

Responses to Draft Decision

The submission made on behalf of the Customer Energy Coalition noted that the Commission’s Draft Decision that there should be no negative carryover amount applied in relation to the 1998-2002 access arrangement period provided a less than satisfactory outcome for consumers, and allows the distributors to exercise strategic behaviour.[310]

[309] Draft Decision, p.125.

[310] Customer Energy Coalition, Response to Draft Decision, prepared by Pareto Associates, August 2002.

Further analysis

The Commission notes the response from the Customer Energy Coalition. However, it considers that the decision taken now as to whether or not to carryover a negative amount from the first access arrangement period cannot now influence distributors' behaviour.

The Commission confirms its earlier view that imposing a negative carryover amount on distributors from the 1998-2002 period would be inappropriate. The Commission therefore confirms its Draft Decision that there will be no negative carryover from the initial access arrangement period.

3.8.10 Adjusting the 1998-2002 expenditure benchmarks

TXU was the only distributor to propose an adjustment to expenditure benchmarks for the 1998–2002 access arrangement period in its original Revisions proposal. In its Draft Decision, the Commission noted that the implied capital expenditure per new connection embodied in TXU's proposed adjustment varied from year to year.[311]

In its Draft Decision, the Commission did not consider there to be enough clarity and consistency in the information provided by distributors to justify an adjustment to the benchmarks for the 1998–2002 regulatory period. However, the Commission did note that it would be prepared to reconsider its position if the distributors were to submit further clear and relevant information that would clarify the matter.

Responses to Draft Decision

In its original proposal, Multinet had not proposed to adjust its 1998-2002 benchmarks. In response to the Draft Decision, Multinet has proposed to adjust its capital expenditure benchmark on the basis of an average cost per connection of $2 270.[312] It indicated that this adjustment comes in light of further analysis of historical data. Specifically, the new proposed benchmark is calculated as the estimated actual connection related capital expenditure for the 1999–2001 period plus forecasts for 2002 divided by the estimated number of connections over the same period. Multinet has noted that it may have erroneously allocated customer numbers between each year within the 1999–2002 period. However, it is confident that the total estimated number of new connections over the period is accurate. It also indicated that the adjustment to the benchmark for the average cost per connection results in an increase in its efficiency carryover amount.[313]

Envestra has indicated that it is prepared to adjust the operating cost benchmark by $11 per connection to account for growth (as proposed by TXU), but has not referred to the changes in capital expenditure benchmarks for 2002.[314]

---

311 Draft Decision, p.122.

312 Multinet, Response to Draft Decision, p.75.

313 Multinet, Response to Draft Decision, p.75.

314 Envestra Draft Decision Submission, p.13.

In its earlier submission accompanying its Access Arrangement Revisions, TXU had proposed adjustments to the capital expenditure benchmarks to reflect growth in the 1998-2002 period.[315]

Further analysis

In its Draft Decision, the Commission proposed that the mechanism for adjusting benchmarks to take account the difference between outturn and forecast growth could also be adopted for the 1998-2002 period.[316] However, it also noted that the clarity and consistency of the information that had been provided to it was insufficient for it to justify making any such adjustment at the time of the Draft Decision. Nevertheless, it left open the possibility of adjusting the 1998-2002 benchmarks if distributors provided further relevant information.

Multinet did not propose any adjustments to the 1998-2002 benchmarks in its original submission, but is now proposing an adjustment of $11 per connection to the operating expenditure benchmarks and $2 270 per connection in relation to the capital expenditure benchmarks to reflect the impact of unanticipated growth. These adjustments would increase the positive efficiency carryover amount calculated for Multinet as well as increase its opening asset base for 2003. The Commission notes that the adjustment to capital expenditure costs now proposed by Multinet is significantly above the $1 582 cost per connection previously identified by Multinet.

The Commission commented in its Draft Decision that the data provided by the distributors lacked clarity and consistency. In relation to data on actual connections over the 1998-2002 period, which are considerably variable, Multinet has noted that its data on the number of new connections in each year may be incorrect, but that the overall number of connections for the period as a whole was correct. The Commission notes that the impact of the growth adjustment on the efficiency carryover amount depends on the year in which the adjustments are made. This implies that any recalculation of the efficiency carryover amount on the basis of the adjustments proposed would not be robust, given the uncertainty in relation to the actual growth figures.

As a result of Multinet's data lacking clarity, and noting the importance of the unit rate when calculating the efficiency carryover, the Commission has decided to adjust Multinet's benchmark by the same unit rate as forecast for the next access arrangement period.

---

315 TXU, Access Arrangement Information, p.7 and 9 and information contained in the GAAR Price Control Model. These adjustments were presented in Table 3.28 of the Commission's Draft Decision (p.122).

316 Draft Decision, p.121.

TXU has clarified that the $1 776 capital expenditure figure per new connection it presented in its earlier submission relates to the costs of connecting smaller customers, and that it has experienced growth in this customer segment in the first access arrangement period. On the basis of this clarification, the Commission considers that it would be most appropriate to adjust TXU's capital expenditure benchmark for the 1998-2002 period on the basis of this cost estimate. Including these adjustments to the benchmarks in calculating the efficiency carryover amount for 1998-2002 continues to imply a negative carryover amount for TXU. However, it does affect the opening asset base for 2002 (see following section).

The Commission notes that the efficiency carryover mechanism proposed for the second access arrangement period involve adjusting the benchmarks to reflect both growth in excess of forecast and growth less than forecast. Envestra consistently experienced growth less than forecast for the 1998-2002 period.

If adjustments were made to the benchmarks to reflect Envestra's lower customer connections, this would increase the amount of its negative carryover. Given that the Commission has decided that there should be no negative carryover from the first access arrangement period, such adjustment does not affect the zero carryover amount previously determined for Envestra. However, adjustments to the 2002 capital expenditure benchmark to reflect lower than anticipated growth would affect Envestra's opening asset base for 2003 (see following section).

The recalculated efficiency carryover amounts for the 1998-2002 period as the result of the above adjustments are presented in table 3.32. Multinet is the only distributor to receive a positive efficiency carryover amount. This amount has been incorporated into Multinet's revenue requirement for the second access arrangement period.

TABLE 3.32
FINAL DECISION: EFFICIENCY CARRYOVER AMOUNT FOR 1998-2002
($ million in July 2001 prices)

	2003	2004	2005	2006	2007
Envestra Albury	-	-	-	-	-
Envestra Victoria	-	-	-	-	-
Multinet	3.9	3.3	8.5	3.3	-
TXU	-	-	-	-	-

3.8.11 Implications of 2002 capital expenditure assumption for 2003 opening asset base

In its Draft Decision, the Commission noted that the opening asset base for 2003 would be determined on the same basis for the last year treatment of efficiency gains as would apply for the second access arrangement period.[317] Capital expenditure for 2002 would be equal to the benchmark level for that year. A subsequent adjustment would be then be made to the asset base in 2008 to take account of any difference between the benchmark and actual level of capital expenditure incurred in 2002.

317 Draft Decision, p.126.

Envestra proposed this approach in its original Access Arrangement submission. Both Multinet and TXU had proposed using forecasts of actual capital expenditure in 2002 in rolling forward the asset base to 2003.[318]

Responses to Draft Decision

TXU contends that in determining the opening asset base for 2003, the Commission should include the forecast level of capital expenditure for 2002, as opposed to the benchmark level for that year. It also claimed that the approach proposed by the Commission contradicts section 8.14 of the Gas Code.[319] Further, it commented that a distributor that has projected capital expenditure for 2002 above the relatively low benchmark level would be penalised by the Commission's proposed approach, as it would effectively result in a negative carryover. TXU highlights that the projection of actual capital expenditure in 2002 of $41 million, in excess of the benchmark expenditure of $20 million, is the result of an increase of 13 520 in new customers, which is 60 per cent above the level assumed in the benchmark, and $10 million unanticipated FRC costs, which will fall outside the Order In Council FRC recovery process.

Whilst Multinet originally proposed that a forecast of 2002 capital expenditure be included in establishing the 2003 capital base, it indicated in its response to the Draft Decision that it would be willing to adopt the Commission's proposal to include the 2002 benchmark amount. Multinet also stated that it would include a new subclause in its proposed Revisions requiring the Commission to incorporate into the capital base for 2008 the difference between actual and benchmark capital expenditure for 2002.[320]

Envestra did not comment on the issue of using benchmark or forecast 2002 expenditure in determining the 2003 opening asset base in its response to the Draft Decision. In its earlier submission, Envestra had rolled forward the asset base on the basis of 2002 benchmark expenditure.

Further analysis

TXU has expressed the view that section 8.14 of the Gas Code requires the Commission to base its decision on the opening asset base for 2003 on the basis of *forecast* capital expenditure for 2002, rather than the original benchmark.[321]

Section 8.14 of the Gas Code applies only:

> Where an Access Arrangement has *expired* … (emphasis added)

318 Draft Decision, p.126. Note that the Draft Decision incorrectly stated that TXU had adopted the Commission's proposed approach.

319 TXU, Response to Draft Decision, p.8.

320 Multinet, Response to Draft Decision, p.101.

321 TXU, Response to Draft Decision, August 2002, p.8. In the Draft Decision, the Commission commented that TXU had adopted the 2002 benchmark in calculating its efficiency carryover amount (p.126). This comment was incorrect. In its GAAR Price Control Model, TXU had adopted the forecast capital expenditure amount for 2002 in calculating the efficiency carryover.

The Commission is of the view that section 8.14 of the Gas Code has no application in connection with the Commission’s 2003 regulatory re-set decision, which is to be made in preparation for the expiry of an access arrangement period rather than the expiry of an Access Arrangement.

In contrast, the Commission considers that sections 8.9 and 8.22 of the Gas Code govern its decision on the appropriate treatment of capital expenditure in the last year of the regulatory period. Specifically, section 8.9(b) of the Gas Code refers to the incorporation of new facilities investment:

> adjusted as relevant as a consequence of section 8.22 to allow for the differences between actual and forecast New Facilities Investment.

Section 8.22 allows the regulator to decide how new facilities investment is to be determined including:

> whether (and how) the Capital Base at the commencement of the next Access Arrangement Period should be adjusted if the actual New Facilities Investment is different from the forecast New Facilities Investment (with this decision to be designed to best meet the objectives of section 8.1).

The Commission also notes that TXU has adopted the principle that the roll-forward of the asset base from the second to the third access arrangement period should be undertaken on the basis of benchmark rather than forecast capital expenditure.

The Commission therefore considers that it is permitted under the Gas Code to roll-forward the asset base on the basis of benchmark rather than projected capital expenditure for 2002. However, the Commission notes TXU’s concern that the adoption of the 2002 capital expenditure benchmark in rolling forward the asset base for 2003 would effectively imply a negative carryover for TXU, given that TXU has spend in excess of its 2002 benchmark capital expenditure. Envestra appears to be in a similar position.The Commission has taken the view that there should be no negative carryover from the first access arrangement period.

As a result, the Commission’s Final Decision is that, if the distributor already has a negative carryover amount for the 1998-2001 period, and updated forecast capital expenditure for 2002 exceeds the original capital expenditure benchmark for 2002, then the updated forecast of capital expenditure should be used in rolling forward the asset base to 2003rather than the (adjusted) benchmark. This principle ensures that there is no ‘negative carryover’ associated with the first regulatory period, either directly or through the treatment of 2002 capital expenditure in rolling forward the asset base. The Commission notes that this principle is only applicable to the first access arrangement period, and will not be applicable to later access arrangement periods. TXU and Envestra both expect to spend above their (adjusted) capital expenditure benchmarks in 2002. The Commission notes that there will be an adjustment to both TXU and Envestra’s asset base in 2008 to take account of any difference between forecast and actual capital expenditure for 2002.

Multinet has a positive efficiency carryover calculated for 1998-2001 and does not anticipate spending in excess of its capital expenditure benchmarks in 2002. As a result, the Commission intends to adopt the same approach in calculating the 2003 opening asset base as it will in 2008 (ie. it will roll-forward the asset base to 2003 on the basis of the adjusted benchmark capital expenditure in 2002).

As discussed above, Multinet's capital expenditure benchmark in 2002 will be adjusted upwards to account for the difference in costs implied by the 4 000 new connections originally forecast and the 9 640 new connections in 2002 now anticipated by Multinet. The Commission notes that Multinet has proposed to include a clause in its proposed Revisions that allows for a subsequent adjustment to the asset base in 2008, in order to take into account any difference between actual and benchmark capital expenditure in 2002. The Commission accepts such a proposal, and notes that it mirrors the arrangements for the second access arrangement period.

3.8.12 Final Decision

The Commission's assumptions in relation to the amounts of the efficiency gain to be carried over from the 1998-2002 period to the 2003-07 period is set out in table 3.33.

In relation to the incentive mechanism that will apply in the second access arrangement period, the Commission requires the distributors to amend their proposed Revisions in the following manner. The Commission notes that some of the amendments relate to the fixed principles proposed by the distributors. These are discussed further in chapter 5.

AMENDMENTS REQUIRED

Envestra is required to amend its proposed Revisions (for both Victoria and Albury) to:

- **allow the carryover of efficiency gains (or losses) for a total of five (rather than ten) years [in clause B7.2(a) and B7.2(c)(1)];**
- **clarify that, in carrying over an accrued negative amount from one year to the next, the negative amount will be multiplied by the pre-tax WACC applying to Envestra for the third access arrangement period [in clause B7.2(c)(2)].**
- **reinstate its earlier proposed clauses 7.2(c)(3) and (4), to permit the Commission to exercise its discretion in choosing whether to apply any negative amounts from the one access arrangement period to the next**

Multinet and TXU are required to amend their proposed fixed principles to:

- **clarify that a negative carryover amount is calculated as the net present value of the carryover amount calculated for individual years, at the pre-tax WACC applying for the third access arrangement period.**
- **permit the Commission to exercise its discretion in choosing whether to apply any negative amounts from the one access arrangement period to the next [in Multinet clause B7.2(a)(9) and TXU B7.2(a)(10)]**

Each of the distributors is required to insert a clause:

- **describing the mechanism for adjusting the expenditure benchmarks in the second access arrangement period to take account of growth in calculating the efficiency carryover amount for the third access arrangement period. The fixed expenditure amounts per connection and the benchmark connection numbers set out in [table 3.27] should be specified as part of this mechanism;**
- **describing the mechanism for adjusting the expenditure benchmarks for the second access arrangement period to take account of changes in scope in calculating the efficiency carryover amount for the third access arrangement period; and**
- **clarifying that the efficiency carryover amount will be calculated as the net amount of the efficiency gains (or losses) relating to capital and non-capital expenditure.**

Envestra is required to:

- **amend B7.2(b)(6)(A) (for both Victoria and Albury) to make clear that the operating expenditure benchmark for the first year of the next regulatory period will be set with regard to actual operating expenditure in the penultimate period of the previous regulatory period and the assumed efficiency gain between the penultimate and final periods embodied in the operating expenditure benchmarks.**

- **amend B7.2(b)(6)(B) (for both Victoria and Albury) to make clear that at the regulatory review for the fourth regulatory period there will be an adjustment to the regulatory asset base to take account of the difference between forecast and actual capital expenditure in the last year of the second regulatory period.**

3.9 Demand forecasts

3.9.1 Introduction

The distributors' proposed Revisions incorporate reference tariffs that have been developed on the basis of forecasts of the expected levels of gas demand over the 2003-07 access arrangement period, including forecasts of gas consumption, peak demand and customer numbers for both Tariff D and V customer classes.

The demand forecasts are an important factor underlying the Commission's assessment of the distributors' proposed reference tariffs. To the extent that actual demand over the regulatory period exceeds forecasts, then the average prices would have been higher than required to deliver the revenue benchmarks derived in this chapter. Thus, the distributors stand to gain where the demand forecasts adopted are too low. The forecast of some of the dimensions of demand is also important for the assessment of future expenditure requirements – for example, the forecasts of customer growth will determine forecasts of future expenditure required to connect new customers.

Under section 8.2(e) of the Gas Code, the key issues for the Commission in assessing the distributors' proposed demand forecasts used to set the reference tariffs is that those forecasts represent *best estimates arrived at on a reasonable basis*. Under the tariff basket form of price control that has been adopted for the 2003-07 access arrangement period, a forecast is required of each of the dimensions of usage upon which charges are set. As the objective when assessing the reference tariffs is to forecast the revenue that would be implied by different average prices,[322] the discussion below uses the term 'revenue forecasts' as a short hand way of referring to the set of demand forecasts for each charging parameter.

In consultation undertaken prior to this review, the Commission outlined a number of possible approaches that would enable it to form a view as to whether the distributors' proposed demand forecasts satisfied the Gas Code requirements. As a result of that consultation, the Commission proposed that distributors should prepare and submit their own demand forecasts together with independent verification that the forecasts are 'the best estimates derived on a reasonable basis'. Each of the distributors supported the Commission's proposed approach to assessing their proposed demand forecasts.

322 That is, by a different initial change to weighted average prices (the P_o adjustment) and different ongoing changes to weighted average prices (the X factor).

3.9.2 Distributors' proposals

The distributors have presented demand forecasts in their Access Arrangement Information for both Tariff V (typically residential and small business customers) and Tariff D (large industrial and commercial customers).

Tariff V relates to customers who use less than 10TJ of gas per annum. These customers account for on average around 50 per cent of the gas demand volumes, but around 95 per cent of the distributors' revenues. The parameters used to forecast Tariff V revenue are customer numbers and consumption volumes based on assumptions about average usage per customer. Tariff V customers can be split into three groups being domestic, commercial and industrial. The key drivers of customer number forecasts are economic factors such as new housing activity (as measured by the anticipated new dwelling completions).

In relation to customer numbers, each of the distributors forecast residential customer growth as well as growth for commercial and industrial customers at levels below that experienced in the first access arrangement period.

In relation to the residential customer growth, the distributors have argued that the factors driving the high levels of customer growth in the first access arrangement period will not have the same effect in the second access arrangement period – particularly the high level of new dwelling completions experienced due to the onset of the GST and the first homebuyers grant. As a result, the distributors' have forecast a decline in the number of residential customer connections. In doing so, Envestra and Multinet have relied upon a report by NIEIR[323], whilst TXU has relied upon a report by BIS Shrapnel[324].

One of the key factors influencing forecasts of Tariff V consumption volumes (and hence average usage per customer) is weather. The distributors have based their 2003-07 consumption volumes on their expectations of future 'normal weather' as measured by the number of Effective Degree Days (EDDs).[325] VENCorp has recently revised its annual EDD forecast standard to 1 445 EDDs for the year 2002.[326] Each of the distributors adopted the revised VENCorp standard for EDDs of 1 445, but has also assumed a declining trend in EDDs over the regulatory period of 5.6 EDDs per annum.

In addition, both Envestra and TXU have forecast reduced average usage for Tariff V customers beyond that attributable to warming weather trends. In doing so, they have argued that the predominant reasons related to the increasing efficiency of household appliances and prevalence of reverse-cycle air-conditioning units. Both Envestra and TXU have provided quantitative and qualitative support for the assumed reduction in average usage per customer.

---

323 National Institute for Economic and Industry Research, The economic drivers of the demand for gas in Victoria, February 2002.

324 BIS Shrapnel, Building in Australia: 2001 to 2016, 21st Edition.

325 Effective degree days (EDDs) is a measure used to model the influence of weather on gas heating demand and is a function of average daily temperature, wind, sunshine hours and season.

326 VENCorp, Annual Gas Planning Review: 2002-06.

Forecasting Tariff D customer usage (predominantly large industrial gas users) generally requires detailed knowledge of each industry sector and company intentions. The distributors' have adopted different approaches to forecasting Tariff D. For example, whilst Multinet has forecast Tariff D load taking into account forecasts of macroeconomic factors, neither Envestra nor TXU took economic forecasts directly into account.

3.9.3 Draft Decision

In its Draft Decision, the Commission reviewed the basis used by each distributor to determine its demand forecasts, and assessed whether the resulting forecasts represented the best estimates in light of other available evidence. The Commission focussed heavily on the distributors' Tariff V forecasts and methodologies, as these have a more significant effect on the assessment of reference tariffs.

In the Draft Decision, the Commission proposed to not accept the distributors' customer growth (new connections) forecasts on the basis that:

- Envestra and Multinet's forecast residential customer growth appeared to be lower than NIEIR's forecast rate of new dwelling completions; and
- each of the distributors appeared to have forecast commercial and industrial customer growth below the levels experienced in the first access arrangement period.

With respect to consumption forecasts, the Commission expressed the view in the Draft Decision that the distributors' proposed warming standard weather trend was reasonable for metropolitan Melbourne, but that it was not clear that this trend was reasonable for regional zones outside metropolitan Melbourne where no warming trend has been observed. It also questioned the supporting evidence provided by Envestra and TXU for either an increase or decrease in average usage per customer and in the absence of further supporting evidence proposed to not to change average usage per customer beyond the abovementioned weather-related reduction.

Regarding Tariff D, the Commission concluded that TXU and Envestra's (Albury) assumption of no growth in usage for these customers did not represent the best estimate arrived at on a reasonable basis. It noted that Multinet's forecasting methodology – which was based upon the relationship between economic output and energy usage at the specific industry levels – was considered robust. As a result, the Commission applied the growth rate implied by Multinet's forecasts to TXU and Envestra (Albury).

As a result of its assessment, in the Draft Decision the Commission adjusted the distributors' proposed demand forecasts by:

- adjusting Envestra and Multinet's forecasts of residential customer growth to reflect 85 per cent of levels experienced in the 1998-2002 access arrangement period, consistent with NIEIR's recommendations;
- adjusting Envestra's forecast of growth in Tariff V commercial and industrial customers to reflect the net customer connections used in 2001;

- adjusting Multinet's forecast of Tariff V commercial and industrial customer growth to reflect that recommended by NIEIR;
- not adopting any change in usage per Tariff V customer from weather normalised 2001 levels for the 2003-07 access arrangement period; and
- including a forecast of growth in Tariff D demand for TXU and Envestra (Albury).

Responses to Draft Decision

In summary, the distributors' responses to the Draft Decision were as follows:

- Multinet argued that the Commission had incorrectly asserted that it had forecast a growth rate in residential customers at 75 per cent of the levels experienced in the 1998-2002 access arrangement period;[327]
- Multinet argued that the Commission had incorrectly forecast customer growth in commercial and industrial customers by stating that growth was below that forecast by NIEIR;[328]
- Multinet revised its demand forecasts to reflect an error in its tariff banding assumptions and a change in its proposed Effective Degree Day (EDD) standard;
- Envestra supported the Commission's view that forecasts of residential growth should be consistent with the NIEIR report;
- Envestra disagreed with the Commission's view that its commercial and industrial customer growth forecasts should be adjusted to reflect actual growth over the 2000-01 financial year;
- Envestra queried the Commission's decision not to accept its Tariff D forecast for Albury, as these were derived on the same basis as its Victorian network (that is, based upon historical demand and survey of customer intentions) – and the latter set of forecasts was accepted.
- Envestra did not accept that the Commission had been conservative in accepting that the declining annual EDD trend would continue throughout the 2003-07 access arrangement period; and
- Envestra and TXU disagreed with the Commission's proposal to reject the argument that average Tariff V usage per customer is declining due to factors other than the warming weather trend observed in metropolitan Melbourne.

The remainder of this section will address each of the issues raised in response to the Draft Decision.

---

327 Multinet, Response to Draft Decision, pp 80-81.
328 ibid., pp 81-82.

3.9.4 Residential customer growth

The distributors' revenue predominantly is derived from Tariff V, which comprises mainly residential customers. Customer growth forecasts are important as they contribute to the growth in Tariff V revenue. The distributors based their proposals for residential customer growth on forecasts of new dwelling completions.

As noted above, in the Draft Decision the Commission concluded that Envestra and Multinet's residential customer growth forecasts were below the rate of new dwelling completions forecast by NIEIR – which was 85 per cent of the levels experienced over the first access arrangement period.

In response to the Draft Decision, Envestra accepted the Commission's decision to adjust growth forecasts to 85 per cent of the average levels experienced in the first access arrangement period. However, it also proposed an adjustment to its 2002 forecast of customer growth, which is discussed further below. On the other hand, Multinet argued that its forecast growth in Tariff V customers for the 2003-07 access arrangement period was the same as that experienced during the 1998-2002 access arrangement period, and not at 75 per cent of this as the Commission had concluded.[329]

The Commission acknowledges that it did not clearly define the period of its analysis for residential customer growth from the first access arrangement period in the Draft Decision. Given that 1998 data is not available for all distributors, and 2001 is the last year for which information is currently available, the Commission assessed the distributors' forecasts of customer growth by comparing the forecast growth over 2003-07 to the actual growth over 1999-01 period. In contrast, Multinet indicated that its analysis focused on comparing its forecasts with growth over the 1998-02 period – which includes forecast data for 2002. The Commission notes that the 2002 forecast of customer growth is equally important for its assessment of reference tariffs given that it will feed into the opening number of customers at the commencement of the 2003-07 access arrangement period.

Following the release of the Draft Decision, the Commission sought further information from the distributors with respect to historic and forecast customer numbers (see table 3.33).[330]

329 Ibid., p 81.

330 The Commission provided distributors with a template that sought information on the number of customers at the beginning and end of each year. The customer information was categorised into three periods, the first being the actual data for the period over 1998 to the end of 2001, the second being the forecast for 2002 (the last year of the first access arrangement period), the third being the forecast for the next access arrangement period (2003-07).

TABLE 3.33

FURTHER DATA ON RESIDENTIAL CUSTOMER GROWTH

Calendar Year	Envestra Albury	Envestra Victoria	Multinet	TXU
1999 – 01 Average	296	9 469	9 069	11 987
2002 (Forecast)	286	8 170	5 436	12 703
2003 – 07 Average	259	7 827	7 982	13 052

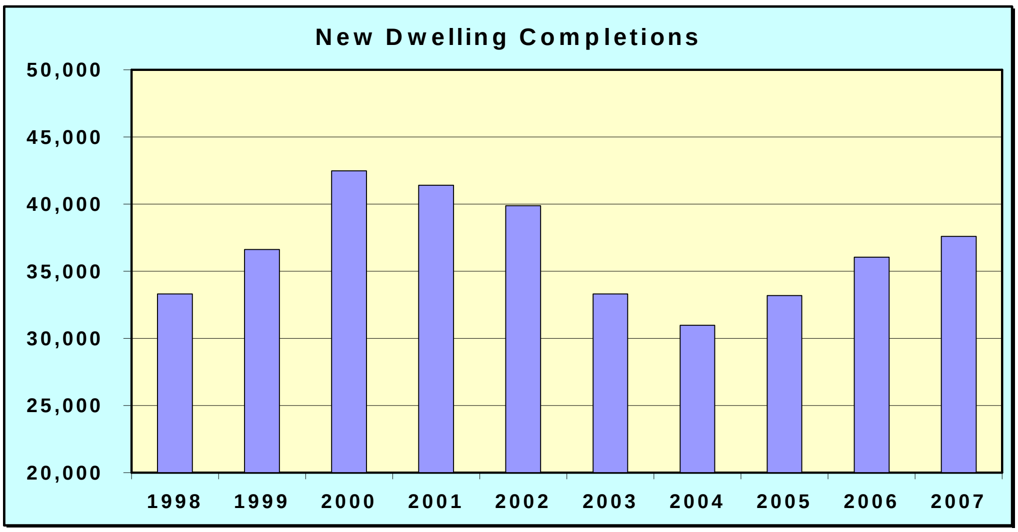
Note: This table shows the simple average of the growth (in numbers) of customers over the calendar years specified. The growth in customers over a calendar year is the difference between the number of customers at the beginning and end of the year.

It is clear from this table that Multinet's 2002 forecast is substantially lower than the average growth in customer numbers it experienced over the 1999-01 period. Multinet indicated that its lower forecast for 2002 reflected the conclusions of NIEIR's report, which it stated had forecast a sharp decline in new dwelling completions due to a reduction in interest for the First Home Owner's Grant and excess supply in other markets. It also argued that housing construction throughout 2001-02 has remained stronger due to lower than expected interest rates, and that it expects growth in 2003 and 2004 to be lower as a result. As noted above, in its response to the Draft Decision, Envestra also proposed adjusting its forecast of customer growth for 2002 downwards to reflect the Commission's acceptance that growth over 2003-07 will be lower than over the first access arrangement period.

In assessing the distributors forecast of customer growth, the Commission relied upon NIEIR's forecasts of new dwelling completions (see figure 3.34).[331] The NIEIR forecasts imply that the average number of new dwelling per annum completions over 2003-07 will be 85 per cent of the average number of new dwelling completions per annum over the 1999-01 period. These forecasts also imply that the number of new dwelling completions in 2002 will be approximately the same as the average number of new dwelling completions per annum over the period 1999-01.

FIGURE 3.34

NEW DWELLING COMPLETIONS – NIEIR FORECASTS



331 National Institute for Economic and Industry Research, The economic drivers of the demand for gas in Victoria, February 2002.

Source: NIEIR, The economic drivers of the demand for gas in Victoria, a report for Envestra, February 2002.

Accordingly, the Commission does not accept Multinet's comment that NIEIR's forecasts imply a lower growth in customer numbers over 2002 than that average experienced over the calendar years 1999-01. The Commission also does not accept Envestra's proposal to adjust downward its forecast for customer growth in 2002 to the level expected over 2003-07 – the NIEIR forecasts would also suggest that this is inappropriate. The Commission also notes that Envestra has accepted that customer growth in 2002 will be in line with that experienced over the first access arrangement period:

> [It had] engaged independent forecasters NIEIR to provide projections of activity in the building industry, including new dwelling completions. NIEIR's forecasts suggest that the current high level of dwelling completions will continue through 2002, before returning to levels more consistent with historic averages in 2003.[332]

As a general rule, it is important to ensure that any benchmark information is used in a manner consistent with the original information upon which the benchmarks were based. In assessing the distributors' forecasts, the Commission has compared their average customer growth forecasts for 2003-07 to actual growth over 1999-01, as well as against housing starts over the same periods. For example, if the Commission compared forecasts of average customer growth over 2002-07 with the growth over 1999-01 (which was implied by Envestra's revision to its 2002 growth), then a different benchmark would be implied by the ratio of housing starts over these periods.[333] Similarly, if the Commission included 1998 in its analysis (as Multinet suggested), then the information above would imply that it would be inappropriate to use a forecast for 2002 based on the average over 1998 to 2001 – a higher forecast than the average of the earlier years would have been appropriate.

Final Decision

On the basis of additional information provided by the distributors' and further analysis, the Commission has adopted a forecast for residential customer growth in 2002 for Envestra and Multinet at the average level experienced during the period 1999-01.[334] This implies a forecast rise in the number of customers over 2002 for Envestra (Victoria) of 9 469 customers and 9 069 for Multinet. The Commission accepts the forecast growth in customers over 2002 for TXU and Envestra (Albury).

The Commission accepts that the forecast growth in customer numbers for the 2003-07 access arrangement period is reasonable for all distributors, given that it is consistent with NIEIR's forecast of new dwelling completions. The table below sets out the forecasts adopted by the Commission in relation to residential customer numbers for the purpose of determining reference tariffs to apply in the 2003-07 access arrangement period.

---

332 Envestra, Access Arrangement Information for Envestra's Victorian Distribution System, 2 April 2002, p 75.

333 A benchmark of 88 per cent rather than 85 per cent would have been used.

334 The growth assumption for Envestra applies to all of Envestra's zones except for the Murray Valley zone. The Commission accepts Envestra's arguments that the Murray Valley zone should be treated differently as it is a new project, and has adopted Envestra's forecasts for this zone.

TABLE 3.35

FINAL DECISION: RESIDENTIAL CUSTOMER NUMBERS 2003-07

Distribution zone	2003	2004	2005	2006	2007
Envestra Albury	16 336	16 595	16 854	17 113	17 372
Envestra Central	383 489	390 329	397 169	404 009	410 849
Envestra North	52 229	53 126	54 023	54 920	55 817
Envestra Murray	2 814	2 948	3 031	3 094	3 152
Envestra Total	**452 054**	**460 050**	**468 046**	**476 042**	**484 038**
Multinet	614 024	622 470	631 462	639 643	646 689
TXU Central	354 201	365 265	375 990	386 933	397 398
TXU West	105 531	107 540	109 551	111 638	113 633
TXU Total	**459 732**	**472 805**	**485 541**	**498 571**	**511 030**

3.9.5 Commercial and industrial customer growth

As noted above, the distributors' forecasts of Tariff V commercial/industrial customer growth were based on actual data from the first access arrangement period as well as forecasts of economic growth.

In its Draft Decision, the Commission noted that Envestra had based its forecast for the 2003-07 access arrangement period on net connections for the 2001 calendar year, which was significantly less than that for the 2000-01 financial year. As a result, it proposed to adjust Envestra's forecast to reflect the 2001 financial year.

The Commission also noted that Multinet and TXU had forecast at levels below those experienced in the 1998-2002 access arrangement period. As a result, it had adopted the average growth rates from the first access arrangement period as the best estimate for the 2003-07 access arrangement period.

In its response to the Draft Decision, Multinet contended that as NIEIR had developed its forecasts of commercial/industrial customer growth, the Commission must have incorrectly assessed its proposal in concluding that Multinet had forecast below the levels forecast by NIEIR.[335]

Envestra stated that it did not believe that it was appropriate to base the forecast of customer growth on the level of net customer connections experienced in the 2000-01 financial year as it reflected the highest annual growth over the first access arrangement period. It argued that the Commission had been inconsistent with the method used to forecast Envestra's customer growth compared to that employed for TXU and Multinet. Further it argued that it already adopted optimistic forecasts of twice the rate of forecast economic growth.

335 Multinet, Response to Draft Decision, p.82.

TXU did not comment on the forecasts adopted by the Commission in the Draft Decision on this matter.

Following the release of the Draft Decision, the Commission sought further information from the distributors with respect to historic and forecast annual customer growth (see table 3.36). This information indicates that Envestra and TXU's forecast growth for 2002 is below the average for the period 1999-01, whereas Multinet's forecasts are significantly above this level. It also indicates that each of the distributors' forecast growth for the 2003-07 access arrangement period at levels below growth for the period 1999-01.

TABLE 3.36
FURTHER DATA ON COMMERCIAL/INDUSTRIAL CUSTOMER GROWTH

Calendar Year	Envestra Albury	Envestra	Multinet	TXU
1999–01 average	25	802	220	161
2002 (forecast)	11	510	375	113
2003–07 average	12	579	196	154

Note: This table shows the simple average of the growth (in numbers) of customers over the calendar years specified. The growth in customers over a calendar year is the difference between the number of customers at the beginning and end of the year.

The Commission sought further information from Multinet with respect to its forecast of commercial/industrial customer numbers, with particular emphasis on the 2002 forecast. In response, Multinet indicated that the forecast for 2002 contained an error and that this figure should be revised downwards by 100 customers.

The Commission accepts Envestra's comment that the Draft Decision did not apply a consistent approach across the distributors. However, the Commission remains of the view that the level of commercial/industrial growth experienced during the period 1999-01 provides the best estimate of future growth. Accordingly, it considers it appropriate that the method used to assess TXU and Multinet's forecasts in the Draft Decision be applied also to Envestra.

Final Decision

The Commission has adjusted the distributors' forecasts for 2002 and 2003-07 to reflect the average level of commercial/industrial growth experienced during the period 1999-01. The table below sets out the forecasts adopted by the Commission in relation to commercial/industrial customer numbers in determining reference tariffs to apply in the 2003-07 access arrangement period.

TABLE 3.37
FINAL DECISION: COMMERCIAL/INDUSTRIAL CUSTOMER NUMBERS 2003-07

Distribution zone	2003	2004	2005	2006	2007
Envestra Albury	451	463	475	487	499
Envestra Central	11 141	11 865	12 589	13 313	14 037
Envestra North	1 268	1 331	1 395	1 459	1 522
Envestra Murray	104	106	108	110	112
Envestra Total	**12 512**	**13 302**	**14 092**	**14 882**	**15 672**
Multinet	16 763	16 983	17 203	17 424	17 644
TXU Central	7 734	7 853	7 971	8 090	8 209
TXU West	5 322	5 364	5 406	5 448	5 490
TXU Total	**13 056**	**13 217**	**13 377**	**13 538**	**13 699**

3.9.6 Average usage per Tariff V customer

The distributors' revenue from Tariff V customers reflects both customer numbers and the average usage per customer. In their proposals, each of the distributors used the average usage per customer in 2001 as the starting point for the next access arrangement period. Envestra and TXU forecast a declining trend over the 2003-07 access arrangement period (of 0.2 per cent and 0.5 per cent per annum, respectively). On the other hand, Multinet forecast usage per customer to remain relatively constant.

In its Draft Decision, the Commission accepted Multinet's forecasts of average usage per customer, but considered that Envestra and TXU had not substantiated their forecasts about a reduced average usage for Tariff V customers. In particular, it queried Envestra and TXU's evidence supporting either an increase or decrease in average usage per customer.[336]

In response to the Draft Decision, Envestra and TXU reiterated their respective arguments in favour of a lower forecast average usage per customer. In particular, they argued that this reflected declining use of domestic gas appliances, greater efficiency of existing gas appliances and increasing use of electric reverse-cycle air-conditioning.

Following the release of the Draft Decision, the Commission obtained the quantitative (statistical) analysis supporting TXU and Envestra's proposals that had been referred to in the submissions accompanying their Access Arrangement Revisions. As well as this statistical analysis, the distributors provided further anecdotal evidence.

336 Multinet also pointed out some inconsistencies between the text of the Draft Decision and the assumptions contained in the financial model. The Commission has addressed these consistencies in this Final Decision.

TXU's analysis was based upon an analysis of the actual consumption data for the three calendar years 1999-01.[337] It adjusted this consumption for the effects of weather, and divided this weather-normalised usage by the average customer numbers in each year to obtain the average usage per customer. TXU then imputed an average reduction over these three years of 0.2 per cent per annum.

Envestra's analysis was similar to that of TXU. It derived annual weather-normalised consumption for individual customers for the period 1999-01,[338] excluding customers for whom weather had little explanatory power on demand (approximately 60 000 customers). It then calculated the average usage per customer for each of these three years given the average customer numbers in each of these years. Its results showed a reduction in average usage of 0.85 per cent between 1999 and 2000, and a reduction of 0.19 per cent between 2000 and 2001, the latter of which was adopted (rounded to 0.2 per cent).

The Commission considers that it is not appropriate to place substantial weight on the statistical analyses provided by TXU and Envestra for a number of reasons:

- both studies have relied on only three observations, which is generally regarded as not satisfying a reasonable level of statistical precision;
- the three years sampled were all warmer than average, and so it is not clear whether the results reflect inadequacies in the adjustments performed for weather; and
- Envestra's approach of excluding customers whose demand is insensitive to weather may well have affected the results given that this implies an increased weight to smaller customers with a heating demand and the exclusion of larger customers without a heating demand.

Accordingly, the Commission does not consider that there is sufficient evidence to suggest that average usage per customer will decline over the 2003-07 access arrangement period.

The Commission notes that in the 1998 review, it adopted a forecast of increasing average demand of 0.5 per cent per annum. Hence, the forecast adopted in the Draft Decision assuming no change in future average consumption is a substantial change to the position adopted at the last review. The Commission also notes that, by accepting the average usage per customer in 2001 in the Draft Decision as the forecast for the 2003-07 access arrangement period, the forecasts for Envestra and TXU for that period are already lower than the average experienced over the 1998-2002 access arrangement period. On this basis, and given the discussion above, the Commission remains of the view that the average levels of consumption experienced in 2001 (in weather normalised terms) provide the best estimate arrived at on a reasonable basis of this parameter over the 2003-07 access arrangement period.

---

337 It had data on 1997 and 1998 but excluded these observations because it only had six months of data for 1997 and because 1998 was affected by the Longford incident.

338 Envestra noted that it has excluded or 1998 data on the basis that it was significantly affected by th Longford outage.

The Commission has accepted Multinet's assumption regarding average consumption per customer. However, while it has accepted the starting point proposed by TXU and Envestra, it has not accepted the assumption of a declining trend. As a result, it has adjusted the Tariff V volume forecasts for Envestra and TXU to reflect a constant average usage per customer over the 2003-07 access arrangement period.

In adjusting these forecasts, the Commission has added the distributors' proposed percentage reduction to their submitted total forecasts and applied this across all tariff bands equally.

3.9.7 Weather standard

One of the key factors influencing forecasts of Tariff V volume is weather. The distributors have based their 2003-07 volume forecasts on the assumption that 'normal' weather will prevail over that period.[339] The relevant measure of 'weather' used to forecast gas consumption is the Effective Degree Day (EDD), which is a function of average daily temperatures, wind, sunshine hours and season.

As discussed above, VENCorp has recently revised its annual EDD forecast standard to 1 445 EDDs for the year 2002,[340] which the distributors adopted as the starting point for their forecast for the 2003-07 access arrangement period. Each of the distributors then assumed a declining trend of 5.6 EDDs per annum over that period. In the 1998 review, the Commission adopted an assumption of normal weather of 1 537 annual EDDs, which reflected the average of the last 20 years as at that time.

In its Draft Decision, the Commission expressed the view that the distributors' proposed warming standard weather trend appeared to be reasonable for metropolitan Melbourne, but noted that it was not clear whether such a trend was reasonable for regional areas outside Melbourne.

Following the release of the Draft Decision, Multinet revised its Tariff V volume forecasts to incorporate new information regarding the expected weather for the 2002-07 access arrangement period. In doing so, it indicated that the adjustment was necessary because:

- it had not been able to meet its forecasts in the 1998-2002 access arrangement period;
- the Commission had proposed to not include any costs associated with weather-hedging;
- analysis of the first seven months of EDD data for 2002 confirmed that the warming weather trend was continuing; and
- further analysis of the CSIRO Melbourne Heating Degree Day (HDD) forecasts provided the most rigorous estimate of Melbourne's future weather.

339 As the distributors have commented in their submissions, the weather over the first regulatory period was far warmer than the historical average (and warmer than the normal weather assumed in the 1998 Review).

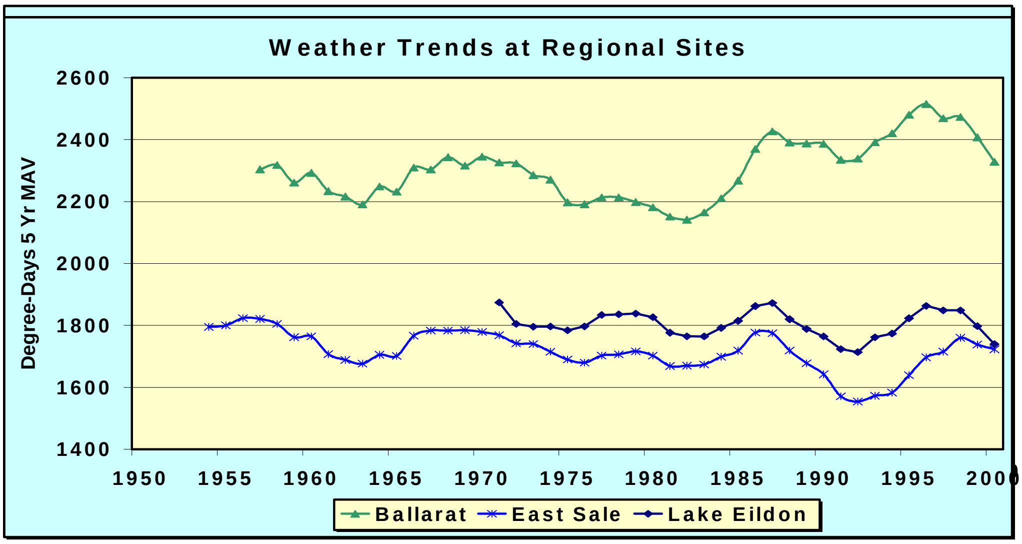
340 VENCorp, Annual Gas Planning Review: 2002-06, www.vencorp.com.au, 15 August 2001

In contrast, the Energy Users Coalition of Victoria emphasised that the Commission had been unduly conservative in a number of areas in its Draft Decision, including in its decision to allow the distributors' forecasts to incorporate a declining EDD trend.[341]

Accordingly, the Commission has undertaken further analysis of the warming weather observed in Melbourne and its effect on gas consumption forecasts. The Commission also notes that since releasing its Draft Decision, the issue of the warming weather trend in Victoria has also been considered by the ACCC in the context of its Draft Decision on GasNet and VENCorp's proposed Revisions and a number of other interested parties have also commented on the issue in that context.

VENCorp analysed the issue of warming weather in both its 2001 and 2002 annual gas planning review of the Victorian transmission system.[342] In doing so, it has observed a warming trend in annual degree-days in the last 50 years based on maximum/minimum temperatures at the Melbourne weather station – located in the CBD.[343] However, it has not observed the same warming trend at other Melbourne metropolitan weather stations – such as Laverton or Moorabbin – or at non-metropolitan centres (see figure 3.38).

FIGURE 3.38
WEATHER TRENDS AT REGIONAL SITES



VENCorp has attributed the increase in average temperatures in Melbourne's CBD to a localised urban warming effect – also known as the 'heat island effect'. This is predominantly caused by the build-up of structures that absorb more heat from the sun, such as buildings, roads and footpaths, as well as the reduction in natural vegetation. VENCorp then used the relationship between annual EDDs and annual degree-days to predict an annual EDD of 1 445 for 2002 (which was a downward revision from its previous forecast of 1 504).

341 Energy Users Coalition of Victoria, Response to Draft Decision, August 2002.
342 Op. cit., VENCorp.
343 A 'degree day' reflects the minimum and maximum temperatures in a day. It is an input in the EDD although, as noted above, EDDs also take account of other weather-related factors.

In interpreting VENCorp's updated forecast, there are a number of important points to note.[344]

- as noted above, VENCorp considered the change in EDDs in Melbourne to be a localised effect. It was not convinced (having regard to the observations summarised in the charts above) that the weather related trend extended outside of the Melbourne CBD. As a result, it did not consider that the decline in EDDs observed for the Melbourne CBD had implied a material decline in weather-related gas demand (ie. heating); and[345]
- consistent with this, while VENCorp revised *downward* its forecast of annual EDDs, it revised *upwards* its assumption about the sensitivity of gas demand to weather. These adjustments cancel each other out – that is, no impact on weather-related gas demand.

Accordingly, VENCorp's analysis suggests that accepting the distributors' forecast trend decline of 5.6 EDDs would require an assumption of an increasing sensitivity of gas demand to weather. Combining these changes would cancel each other out.

As noted above, each of the distributors has used a CSIRO report produced for GasNet to support their arguments in favour of a state-wide warming trend.[346] CSIRO's forecast of the trend changes in temperatures included two components, first - a regional weather trend (which was projected from climate models), and second - an estimate of the urban heating effect, based upon temperatures observed at the Melbourne-CBD weather station. The first of these trends would apply state-wide, whereas the second of these trends is localised and, on VENCorp's analysis discussed above, was not considered to affect heating demand. The Commission makes the following observations on the CSIRO estimates:[347]

- CSIRO's predictions of degree-days over the 2003-07 access arrangement period are substantially uncertain as a result of the imprecise nature of the climate change modelling. VENCorp's assumption about degree-days for 2002 (1170) is within CSIRO's range for degree-days in 2007 (between 1061 and 1205);
- as discussed above, the regional warming component of the trend identified by CSIRO is not consistent with observed degree-days for the weather stations outside of the CBD. While the downward trend in the degree-days measured at the Melbourne CBD weather station is clear, there is no observable trend at the Moorabbin and Laverton weather stations, and little evidence of trends at the regional weather stations referred to; and
- even if CSIRO's regional warming predictions are incorporated into demand forecasts, the regional warming trend is only a component of the total trend it predicted.

---

344 VENCorp, Submission onACCC Draft Decisions on GasNet's and VENCorp's proposed Revised Access Arrangements for the PTS, 13 September 2002.

345 Op. cit., VENCorp Annual Gas Planning Review, presentation.

346 GasNet, Access Arrangement Submission – Annexure 8 - CSIRO Report, Projected changes in temperature and heating degree-days for Melbourne - 2003-07, November 2001.

347 These comments draw on the views expressed by VENCorp: Op. cit., VENCorp (Submission).

Having considered the evidence, the Commission accepts VENCorp's analysis that the trend decline observed in degree-days (and, by implication, EDDs) is a localised effect, and unlikely to have a material impact on weather-related gas demand. In particular, it accepts that the evidence from outer-urban and regional weather stations does not demonstrate any clear trend, either upwards or downwards. Further, it considers that, given the inherent imprecision in CSIRO's climate modelling, and its apparent inconsistency with observed degree-days outside of the Melbourne CBD, it would not be appropriate to place substantial weight on these estimates.

Final Decision

The Commission's further analysis of the warming weather trend suggests that the distributors' proposals to continue the declining trend in annual EDD for the 2003-07 access arrangement period based on the revised VENCorp weather standard is inappropriate. In particular, the Commission considers that the warmer weather experienced in Melbourne's CBD appears to be due to a localised urban effect and does not appear to affect gas heating load in other areas across the state. The Commission has also noted concerns with the application of the CSIRO report to forecast gas demand throughout Victoria.

On the basis of this further analysis, the Commission considers that the best estimate arrived at on a reasonable basis of forecast gas load across Victoria for the 2003-07 access arrangement period is the VENCorp standard of 1 445. Accordingly, it has adopted this estimate and adjusted the distributors' demand forecasts.

3.9.8 Multinet tariff banding

The distributors levy Tariff V tariffs according to whether the consumption occurs during peak or off-peak periods as well as according to certain tariff bands. The assumptions made regarding the proportion of consumption that would sit within each tariff band can have a significant impact on Tariff V revenue.

In response to the Draft Decision, Multinet proposed to revise its tariff banding forecasts to account for an error in its original submission. It noted that it had erroneously used its 2001 actual (that is, not weather normalised) consumption to forecast the proportion of gas consumption that would fall within each band.[348] As weather can have a large impact on gas usage, failing to adjust for weather can lead to material errors in the forecast of proportion of consumption within each band. Table 3.39 sets out Multinet's original and revised estimates of the proportion of consumption that would fall within each band.

[348] Multinet, Response to Draft Decision, p.83.

TABLE 3.39

MULTINET'S REVISED TARIFF BANDING ASSUMPTIONS

	2001 (Actual)	Revised (Normalised)
Peak		
0 – 0.1 GJ	15.5%	14.6%
0.1 – 0.2 GJ	11.9%	11.2%
0.2 – 1.4 GJ	20.5%	23.7%
> 1.4 GJ	4.4%	4.4%
TOTAL PEAK	52.3%	53.9%
Off Peak		
0 – 0.1 GJ	24.0%	20.6%
0.1 – 0.2 GJ	9.5%	7.4%
0.2 – 1.4 GJ	9.0%	12.7%
> 1.4 GJ	5.2%	5.3%
TOTAL OFF PEAK	47.7%	46.1%

In a supplementary submission, Multinet indicated that its tariff banding approach involved four steps, namely: [349]

- apportioning billed consumption within each month, noting the majority of bills span three months. Multinet applied the following ratios: 25 per cent in the month the bill was issued; 55 per cent in the month immediately preceding when the bill was issued; and 20 per cent in the two months prior to the bill being issued;
- allocating historical banded consumption (from the distributors' billing system) and EDDs according to the ratios outlined above. It performed linear regressions between consumption and EDDs to normalise consumption for weather. This produced an estimate of the weather-related demand applicable to each of the tariff bands;
- reconciling estimates of the weather-related demand. Multinet manually adjusted its estimates of the weather-related component of demand for each band to reconcile the total of the weather-sensitive demand to estimates obtained by a different method (which was a weather-related demand of 18 TJ/EDD); and[350]
- forecasting the weather-normalised consumption for each tariff band for each year of the 2003-07 access arrangement period based on its revised weather standards. It then derived an average of these tariff band proportions and applied this average equally across all five years 2003-07.

349 ibid.; Multinet, Supplementary Demand Forecast Information, 20 August 2002.

350 The estimate of the total weather-related demand was obtained from aggregate information for all customers from custody transfer meters. The data from this source is reliable and available on a daily (or even intra-daily) basis.

The Commission has reviewed the approach used by Multinet to derive its tariff bands, and has a number of concerns.

First, with regard to its manual adjustments, Multinet appears to have apportioned the majority of the difference in its estimates of weather-related demand to the third tariff band, as shown in table 3.40.

TABLE 3.40
MULTINET'S REGRESSION EQUATIONS

Tariff Bands	Regression Estimates		Multinet Adjusted Results	
	TJ/EDD	Base TJ	TJ/EDD	Base TJ
Band 1	2.08	1 133	2.48	1 003
Band 2	3.90	264	4.40	164
Band 3	7.66	139	10.16	139
Band 4	1.01	240	1.01	240
Total	**14.64**	**1 776**	**18.04**	**1 546**

Source: Spreadsheet model provided to the Commission by Multinet on 6 September 2002

The Commission is concerned that this adjustment has materially affected Multinet's forecasts of the split of consumption into the different bands, and does not appear to be soundly based.

Second, the Commission notes that one of the data points in Multinet's analysis appears to contain a negative value for band 4. The Commission has sought further clarification from Multinet on this point. In response, Multinet explained that it had experienced billing system problems and that its retailer had adjusted for this error in the following period. Multinet made no attempt to manually correct this error, either prior to or after performing its regression analysis. Accordingly, the Commission is concerned about the validity of the data obtained from Multinet's billing system.

Third, Multinet appears to have used the wrong variables in its estimated weather-normalisation regression equations. Essentially, Multinet has used two sets of information for gas demand and EDDs. For gas consumption, Multinet used consumption data that spanned three months, which it then allocated between months to create a proxy for monthly consumption. For EDDs, it used monthly EDDs, but then averaged these EDDs over the three-month period to create a proxy EDD consistent with the three months of consumption data. Given these variables, two robust relationships could be estimated – the relationship between the three months of consumption and the proxy EDD over that period, or the proxy for monthly consumption and the EDDs for that month. Multinet did neither – it estimated the relationship between the proxy for monthly consumption, and the proxy EDD over a three-month period. The Commission does not consider this to be appropriate.

Given the Commission's concerns about Multinet's tariff-banding assumptions, it compared Multinet's tariff bands with those of the other distributors (see 3.41). The Commission examined the make-up of customers for each of the distributors, and considers that the customers are sufficiently similar to make direct comparisons.

TABLE 3.41
DISTRIBUTORS' PROPOSED TARIFF BANDING ASSUMPTIONS

	Envestra	TXU	Multinet's Proposal
Peak			
0 – 0.1 GJ	15.8%	17.6%	14.6%
0.1 – 0.2 GJ	11.7%	12.8%	11.2%
0.2 – 1.4 GJ	17.6%	14.8%	23.7%
> 1.4 GJ	6.7%	7.2%	4.4%
Total Peak	51.7%	52.3%	53.9%
Off Peak			
0 – 0.1 GJ	24.9%	27.8%	20.6%
0.1 – 0.2 GJ	8.0%	7.4%	7.4%
0.2 – 1.4 GJ	7.5%	5.1%	12.7%
> 1.4 GJ	7.8%	7.4%	5.3%
Total Peak	48.3%	47.7%	46.1%

This comparison appears to justify the Commission's concerns about Multinet's manual adjustment to the proportion of weather-related consumption in the third band. In particular, Multinet's assumption about the proportion of consumption within this band far exceeds that of the other distributors.

The Commission notes that Envestra adopted a different approach to that of the other distributors to estimate its tariff bands. Whilst Multinet and TXU have estimated tariff band consumption on an aggregate basis, Envestra undertook its weather-normalisation using data at the customer level. The Commission considers that Envestra's approach provides a sound basis for estimating consumption by tariff band, as it allows for a greater degree of confidence in the statistical results. Given the similarities in the make-up of the distributors' customer bases, the Commission considers that Envestra's tariff banding assumptions should also apply to Multinet.

As a check on this assumption, the Commission also estimated what it considered the correct relationships between Multinet's data on gas consumption and EDDs, as discussed above. The Commission's analysis produced an estimate of the tariff bands for Multinet that was very similar to that of Envestra (indeed, the adoption of Envestra's banding assumptions for Multinet rather than that estimated directly by the Commission favours Multinet).

Final Decision

The Commission does not consider that Multinet’s tariff banding assumptions provide the best estimates arrived at on a reasonable basis for deriving forecasts of consumption by tariff band given the deficiencies in its approach outlined above. In contrast, the Commission considers that Envestra’s approach provides a reliable means of estimating the proportion of consumption that would fall within each tariff band and accepts it is the best estimate arrived at on a reasonable basis. Given the similarities between the customer base of Multinet and Envestra, the Commission has adopted Envestra’s tariff band forecast as the best estimate arrived at on a reasonable basis for Multinet. However, the Commission notes that this banding assumption is similar to that which the Commission estimated from Multinet’s data after remedying the deficiencies in its approach.

3.9.9 Tariff D Albury

Tariff D customers are typically large industrial users that are charged according to their maximum hourly demand (MHQ). As noted in the Draft Decision, the distributors adopted different approaches to forecasting Tariff D demand. Multinet used forecasts of economic growth to forecast demand, Envestra used a customer-by-customer approach, whereas TXU did not forecast any change in demand for the 2003-07 access arrangement period.

In its Draft Decision, the Commission considered that Envestra’s (Albury) and TXU’s forecasts for Tariff D demand did not represent the best estimates arrived at on a reasonable basis, as they did not take into account economic growth. The Commission adjusted the demand forecasts in order to include an annual estimate of economic growth of 1.2 per cent, which reflected the average growth forecast by Multinet.

In response, Envestra argued that it had adopted the same approach for forecasting demand for its Albury network as it had for Victoria – which the Commission had accepted. It therefore reiterated its view that the approach adopted for the Albury network was appropriate.

The Commission acknowledges that Envestra has used the same customer-by-customer approach to forecasting Tariff D demand for both its Albury and Victorian networks. However, it does not agree that the two methodologies are the same. In particular, Envestra adopted a ‘rule of thumb’ to capture economic growth (at an average of 2.5 per cent) for its Victorian network, but has not used the same approach for its Albury network where forecast demand growth is zero.

The Commission considers that a forecast growth in demand of 1.2 per cent, as proposed by Multinet, is the best estimate arrived at on a reasonable basis for Tariff D. It notes that Envestra has forecast growth for its Victorian network, as has Multinet. It also notes that TXU has not responded to the Draft Decision, which adjusted its forecasts to include growth. The level of growth adopted by the Commission is at the midpoint of Envestra’s proposal for its Victorian network and its Albury network. The table below sets out the forecasts of growth in demand for Envestra’s Albury network.

TABLE 3.42
TARIFF D DEMAND – ENVESTRA ALBURY

	Proposed	Adjusted				
	2003-07	2003	2004	2005	2006	2007
First 10 GJ/hr	84	86	87	88	89	90
Next 40 GJ/hr	126	129	131	132	134	135
Remaining GJ/hr	308	315	319	323	327	330
	518	**531**	**537**	**543**	**549**	**556**

3.9.10 Ancillary reference services

In its previous consultation papers, the Commission expressed the view that reference services should include the standard transportation service, as well as the more important of the ancillary reference services for which the distributors were likely to remain a monopoly provider. In addition, the Commission took the view that, rather than being included under the weighted-average price cap, the prices for the ancillary reference services should be established at the start of the access arrangement period and escalated for inflation. The expected revenue from these services is then deducted from the overall revenue requirement. The Commission's approach with respect to these services is discussed in more detail in chapter 2.

The distributors were invited to propose prices and forecasts of quantities for each service. All of the distributors' proposed prices for these reference services; however, only Envestra provided forecasts of quantities.

The Commission has accepted that Envestra's forecasts represent best estimates arrived at on a reasonable basis. Given the absence of proposed forecasts from TXU and Multinet, the Commission has developed its own forecasts. The Commission's forecasts for Multinet and TXU have been based upon Envestra's forecasts, but adjusted for differences in customer numbers. The Commission considers that these forecasts represent best estimates arrived at on a reasonable basis.

3.9.11 Summary of demand forecast assumptions

Adjustments to distributors' proposals

The Commission has assessed the distributors' proposed demand forecasts against the requirements of the Gas Code and considered in particular whether their proposed forecasts represent the best estimates arrived at on a reasonable basis. As a result of the analysis presented above, the Commission has made a number of adjustments. Specifically, it has:

- adjusted Envestra's and Multinet's residential customer growth forecasts in 2002 to the levels experienced during the period 1999-01. The Commission has accepted that the forecasts of residential growth for the 2003-07 access arrangement period are reasonable as they are not inconsistent with the forecast of new dwelling completions forecast by NIEIR.

- adjusted the forecasts of Tariff V commercial/industrial customer growth for both 2002 and the 2003-07 access arrangement period for all distributors (except for Envestra Albury). The Commission decided that the forecasts should be equal to the levels experienced during the period 1999-01.
- not accepted the proposal by Envestra and TXU that average usage per customer will decline over the 2003-07 access arrangement period due to factors other than weather.
- not accepted the distributors' proposal that the reduction in annual EDD will continue throughout the 2003-07 access arrangement period;
- not accepted Multinet's revised tariff banding as the analysis contains statistical deficiencies, and instead adopted Envestra's tariff banding assumption for Multinet; and
- adjusted Envestra's forecast of Tariff D demand for its Albury network to reflect economic growth.

Final Decision

As a result of the adjustments made to the distributors' proposals, the Commission has derived demand forecasts for the purposes of estimating forecast tariff revenue. The following section outlines the steps undertaken by the Commission to derive at final forecasts for Tariff V customer numbers, Tariff V consumption by tariff band and Tariff D demand by tariff band.

TARIFF V CUSTOMER NUMBERS

The Commission derived forecasts of Tariff V customer numbers using the following steps:

- it added the forecast net customer connections for the 2002 calendar year (outlined in section 3.8.5) to the distributors' reported customer numbers as at 1 January 2002 to derive a forecast of customers as at 1 January 2003;
- it then derived an annual forecast of net customer connections for the period 2003-07. In the case of residential customers, the Commission added the forecast proposed by the distributors. For commercial/industrial customers, the Commission added the average annual customer growth observed for the period 1999-01; and
- the end result of this process meant that the Commission had derived a forecast of customers as at the start and end of each calendar year. For the purposes of deriving a forecast of Tariff V revenue, the Commission calculated the average customer numbers for each calendar year.[351] Table 3.42 below sets out the forecasts of Tariff V customer numbers.

---

351 The Commission notes that some of the distributors have used customer numbers as at either the start or at the end of the calendar year when forecasting Tariff V revenue.

TABLE 3.43
FINAL DECISION: TARIFF V CUSTOMER NUMBERS

	Net customers	2002	2003	2004	2005	2006	2007
Envestra Albury	As at start	15 921	16 207	16 466	16 725	16 984	17 243
	As at end	16 207	16 466	16 725	16 984	17 243	17 502
	Connections	286	259	259	259	259	259
	Average		**16 336**	**16 595**	**16 854**	**17 113**	**17 372**
Envestra Victoria	As at start	425 435	434 577	442 485	450 320	458 125	465 920
	As at end	434 577	442 485	450 320	458 125	465 920	473 714
	Connections	9 142	7 908	7 835	7 805	7 795	7 795
	Average		**438 531**	**446 403**	**454 222**	**462 022**	**469 817**
Multinet	As at start	601 036	610 105	617 942	626 997	635 926	643 360
	As at end	610 105	617 942	626 997	635 926	643 360	650 017
	Connections	9 069	7 837	9 055	8 929	7 434	6 657
	Average		**614 024**	**622 470**	**631 462**	**639 643**	**646 689**
TXU	As at start	440 186	452 889	466 575	479 036	492 046	505 096
	As at end	452 889	466 575	479 036	492 046	505 096	516 965
	Connections	12 703	13 686	12 461	13 010	13 049	11 869
	Average		**459 732**	**472 805**	**485 541**	**498 571**	**511 030**

TARIFF V CONSUMPTION

The Commission derived its forecasts of Tariff V consumption using the following steps. First, it calculated the average forecast consumption for all Tariff V customers for 2003 implied by the distributors' proposals by dividing their total forecast consumption for 2003 by their forecasts average customer numbers for that year, and then adjusting the results for Envestra and TXU to exclude their assumptions of a declining average usage per customer (which the Commission did not accept). Table 3.44 below sets out the average Tariff V consumption assumed for each distributor.

TABLE 3.44
FINAL DECISION: AVERAGE TARIFF V CONSUMPTION

	Proposed 2003 average consumption	Adjusted 2003 average consumption
Envestra Albury	62.0	62.2
Envestra Central	69.6	69.9
Envestra North	63.2	63.4
Envestra Murray	50.8	50.8
Multinet	72.4	72.4
TXU Central	60.1	60.7
TXU West	60.3	60.9

Second, the Commission calculated annual consumption for each distribution zone by multiplying the forecast customer connections by the average consumption (see table 3.45 below).

TABLE 3.45
FINAL DECISION: FORECAST TARIFF V CONSUMPTION (TJ)

	2003	2004	2005	2006	2007
Envestra Albury	1 044	1 061	1 078	1 095	1 112
Envestra Central	27 588	28 117	28 646	29 175	29 704
Envestra North	3 394	3 455	3 516	3 577	3 638
Envestra Murray	148	155	159	163	166
Multinet	45 675	46 302	46 969	47 577	48 104
TXU Central	21 985	22 664	23 323	23 995	24 638
TXU West	6 747	6 871	6 996	7 126	7 250

Third, the Commission adjusted the forecast total consumption for the annual decline in EDDs as proposed by the distributors – which the Commission did not accept. Table 3.46 below sets out the weather sensitivity as proposed by the distributors, whilst table 3.47 sets out the forecast Tariff V consumption by distribution zone.

TABLE 3.46
FINAL DECISION: WEATHER SENSITIVITY

	TJ/EDD	Annual EDD adjustment	Annual TJ adjustment
Envestra Albury	11.45	5.6	64.1
Envestra Victoria	0.49	5.6	2.7
Multinet	18.15	5.6	101.6
TXU	8.45	5.6	47.3

TABLE 3.47
FINAL DECISION: ADJUSTED FORECAST TARIFF V CONSUMPTION (TJ)

	2003	2004	2005	2006	2007
Envestra Albury	1 047	1 067	1 086	1 106	1 125
Envestra Central	27 652	28 245	28 838	29 431	30 024
Envestra North	3 458	3 583	3 708	3 833	3 959
Envestra Murray	212	283	352	419	486
Multinet	45 776	46 505	47 274	47 984	48 612
TXU Central	22 032	22 759	23 465	24 184	24 874
TXU West	6 794	6 966	7 138	7 315	7 487

Finally, the Commission calculated annual Tariff V consumption by tariff band for each distribution zone by multiplying the annual consumption calculated above by the distributors proposed tariff band percentages (as noted above, the Commission adjusted Multinet's tariff bands to reflect those of Envestra).

TARIFF D DEMAND

In order to derive forecasts of Tariff D demand, the Commission took the proposed demand forecasts by tariff band and adjusted for growth for Envestra Albury and TXU, as noted above. Table 3.47 below sets out the Tariff D demand forecast adopted by the Commission in this Final Decision.

TABLE 3.48
FINAL DECISION: TARIFF D FORECAST DEMAND

	2003	2004	2005	2006	2007
Envestra North Central					
0 – 10	1 727	1 802	1 877	1 877	2 027
10 – 50	2 037	2 113	2 189	2 189	2 340
> 50	3 370	3 415	3 452	3 452	3 528
Envestra Murray					
0 – 10	30	30	30	30	30
10 – 50	40	40	40	40	40
> 50	-	-	-	-	-
Envestra Albury					
0 – 10	86	87	88	89	90
10 – 50	129	131	132	134	136
> 50	316	319	323	327	331
Multinet					
0 – 10	1 732	1 771	1 801	1 798	1 817
10 – 50	1 732	1 771	1 801	1 798	1 817
> 50	819	837	852	850	859
TXU					
0 – 10	2 703	2 735	2 768	2 801	2 835
10 – 50	3 469	3 510	3 553	3 595	3 638
> 50	5 040	5 100	5 161	5 223	5 286

4 REFERENCE TARIFF POLICY ISSUES

The Gas Code requires that an Access Arrangement include a reference tariff (or tariffs) for reference services and a reference tariff policy. This chapter sets out the Commission's Final Decision in relation to a number of issues related to the distributors' proposed reference tariff policies.

In particular, this chapter sets out the responses to the Commission's Draft Decision and the subsequent analysis in relation to:

- the form of distribution price control;
- provisions in relation to tariff structures;
- rebalancing controls to apply to tariffs during the 2003-07 regulatory period;
- the treatment of the correction factor arising under the price control for the 1998-2002 regulatory period;
- recovery of FRC costs for Envestra's Albury network;
- the tariff approval and variation process to apply for the 2003-07 regulatory period; and
- the provisions that enable a distributor to seek to pass-through changes in costs associated with certain defined events into reference tariffs.

In addition, this chapter describes how the revenue benchmarks that have been derived for each distributor in the previous chapter are translated into price controls for the defined reference services, and the derivation of the associated X factors.

4.1 Gas Code requirements

As noted above, the Gas Code requires that an Access Arrangement include a reference tariff (or tariffs) for reference services and a reference tariff policy.[352] A reference tariff policy describes the principles used to determine reference tariffs.

The Gas Code specifies a number of objectives that are relevant to reference tariffs and the associated reference tariff policy. The reference tariffs and the reference tariff policy must both, in the relevant regulator's opinion, comply with the reference tariff principles described in section 8 of the Gas Code.

Section 8.38 of the Gas Code requires that, to the maximum extent that is commercially and technically reasonable, the portion of total revenue that a reference tariff should be designed to recover should include:

- all of the total revenue which reflects costs that are directly attributable to the reference service; and
- a share of the total revenue that reflects costs incurred that are attributable to providing the reference service jointly with other services.

---

[352] Sections 3.3 and 3.5 of the Gas Code.

Further, section 8.42 of the Gas Code requires that the design of the reference tariff should ensure that a particular user's share of the portion of total revenue to be recovered also accords with these principles.

In determining the allocation of shared costs between reference services and between users, the Gas Code requires that such an allocation is consistent with the objectives set out in section 8.1. Although meeting all the section 8.1 design factors is necessary (subject to conflicts between these design principles). The objectives in section 8.1 that are most relevant to cost allocation and tariff design are:

- not distorting investment decisions in pipeline transportation systems or in upstream and downstream industries; and
- efficiency in the level and structure of the reference tariff.[353]

The Gas Code therefore requires the Commission to form a view about the efficiency of cost allocation reflected in distributors' tariffs. This requires looking at both the level of tariffs at the commencement of the new access arrangement period, and also the incentives and constraints on tariff movement over the coming regulatory period.

In addition to the Gas Code provisions, the distributors' existing Access Arrangements contain a number of fixed principles that distributors' tariffs are required to comply with. These are discussed further in the relevant sections below.

4.2 Form of distribution price control

4.2.1 Gas Code provisions

The manner in which a reference tariff may vary within an access arrangement period through implementation of the reference tariff policy is within the discretion of the service provider, subject to it complying with factors set out in section 8.2 of the Gas Code.[354]

The Gas Code permits the service provider to set tariffs on the basis of:

- a 'cost of service' approach, where tariffs are continuously adjusted in the light of actual cost outcomes; or
- on a 'price path' approach, which is forecast to deliver a certain revenue stream, but which is not adjusted to account for subsequent events until commencement of the 2003-07 access arrangement period; or
- a combination of these approaches.

353 These principles are set out in section 8.1(d) and (e) of the Gas Code. The discussion of Gas Code requirements in relation to cost allocation and tariff design above reflects the Office of the Regulator-General's 1998 Final Decision on the Access Arrangements applying to the Victorian gas distributors, p.122, as well as the Commission's Draft Decision.

354 Section 8.3 of the Gas Code.

4.2.2 Draft Decision

Each of the distributors proposed a 'tariff basket' form of price control as part of their proposed Revisions. The Commission has previously noted that it considers that a tariff basket form of price control meets the Gas Code objectives of achieving efficiency in the level and structure of pricing most effectively.[355] It is also consistent with the 'price path' approach to setting tariffs set out in section 8.3 of the Code. As a result, in the Draft Decision the Commission proposed to accept the distributors' proposed tariff control formula, subject to an amendment being made to include an adjustment to the price control formula (referred to as an L-factor) to permit distributors to adjust reference tariffs for the calendar year to recover actual licence fees paid in the previous financial year.[356]

The smoothed revenue requirement, as determined by the Commission, that is to apply to each distributor for each year is set out in [section 3.10]. The first L-factor will be incorporated into tariffs in 2003. The denominator of the L_{2003} factor will be set at 1 for the purposes of applying the price control formula in 2003.[357]

In addition, the Commission's Draft Decision required each of the distributors to delete the clause referring to the separate identification of 2003 tariffs. This clause reflects a provision included in the Electricity Distribution Price Determination, which is not required for the gas Access Arrangements.

4.2.3 Responses to Draft Decision

Envestra generally supported the Commission's approach to treating the recovery of licence fees separately from the recovery of other operating costs, via the inclusion of an L-factor in the price control formula.[358] TXU noted that it was willing to consider the inclusion of an L-factor, although it had concerns about its operation in 2003.[359] Multinet suggested there is enough certainty in relation to licence fees over the 2003–07 access arrangement period to include them in forecasted operating costs and therefore the revenue requirement.[360] However, it stated that it was prepared to accept an L-factor, provided that it stood outside the formula for the rebalancing control.

Each of the distributors expressed the concern that if the L-factor was included within the rebalancing control, the distributors would be unable to recover the full amount of the licence fees in years in which there was a significant increase in fees.[361]

---

355 Position Paper, p.58.

356 Licence fees in Victoria are currently levied on a financial year basis whilst tariffs are approved on a calendar year. The Commission understands that licence fees for Envestra's Albury network are also levied on the same basis.

357 This will have the effect of adding on the 2001-02 licence fees to average prices in 2003, as these will be subtracted from the benchmark revenue requirement.

358 Envestra, Response to Draft Decision, p.14.

359 TXU, Response to Draft Decision, p.19.

360 Multinet, Response to Draft Decision, p.90.

361 ibid; TXU, Response to Draft Decision, p.20; Envestra, Response to Draft Decision, p.14.

TXU noted that it would be unable to recover licence fee costs for the 2001–02 financial year as a result of removing the licence fee from the revenue requirement for 2003 and imposing the proposed rebalancing constraint for 2003, which requires all tariff components to fall by at least 1 per cent.[362] TXU noted that its situation is unique from that of the other distributors, due to the P_0 factor proposed for TXU in 2003.

With regard to the formula for determining the licence fee adjustment, Multinet expressed the view that the terms SR_{t-1} and SR_t should both be replaced by the term $SR_{t-2.}$[363] This would ensure that the L-factor percentage adjustment permitted under the price control is not reduced in years where licence fees remain unchanged but the smoothed revenue requirement rises.

TXU also noted that the Commission did not appear to have considered the time lag between when a distributor pays the licence fee and when it is able to recover this cost in the form of higher tariffs. It proposed that the adjustment included in the price control formula should reflect the time value of money, such as the WACC escalation.[364]

Each of the distributors agreed to delete the clause referring to the separate identification of 2003 tariffs.[365]

4.2.4 Further analysis

The Commission notes that both TXU and Envestra appeared to support the Commission's approach of treating the licence fee outside of the revenue requirement. Multinet's view that there is sufficient certainty for the licence fee to be included in the revenue requirement for 2003-07 is inconsistent with the concern it expressed about the impact of significant future increases in the licence fee on the rebalancing constraint.

The Commission notes that the concerns expressed by the distributors with respect to including the L-factor in the price control formula primarily relate to the risk of under-recovering licence fee costs as a result of the interaction between the L-factor and the rebalancing control. In addition, even if this interaction did allow the distributors to recover the licence fees in full, an increase in licence fees would still lessen the extent to which distributors could effectively rebalance tariffs under the rebalancing control. For example, if licence fees rise, leading to an L factor of CPI+1 per cent, then tariffs will generally increase by CPI+1 per cent.[366] Where there is a rebalancing constraint of CPI+2 per cent on tariffs in any one year, this reduces the effective scope for rebalancing under the rebalancing constraint to 1 per cent.

---

362 TXU, ibid., p.20.

363 Multinet Response to Draft Decision, p.90.

364 TXU, Response to Draft Decision, p.20.

365 Multinet, Response to Draft Decision, p.91; TXU, Response to Draft Decision, p.20; Envestra, Response to Draft Decision, p.15.

366 Some tariffs may increase by more than 1 per cent and some by less than 1 per cent, provided that the overall control on the increase in weighted average tariffs is met. This example assumes an X factor of zero, for clarity.

However, the Commission does not believe that treating the licence fee as a straight pass-through amount, outside the scope of the main price controls, would be the most appropriate way to address the concern expressed by distributors. Such an approach would necessitate the specification of how such a pass-through amount should be allocated between different tariffs. That is, it would not be enough to calculate a licence fee pass-through amount of $L, but it would also be necessary to specify how that $L should be added to the different tariffs and tariff components charged by distributors. Options would include all tariff components rising by the same percentage (in order to recover $L in total), or a separate $/annum customer charge to be levied (as in the case of FRC cost recovery). As a result, the distributors' flexibility to determine how licence fees are reflected in final tariffs would be reduced.

The Commission's preferred approach to addressing the distributors' concern regarding the interaction of the L-factor with the rebalancing constraint is therefore to explicitly include the L-factor adjustment within the rebalancing constraint. This approach ensures that the distributors' effective ability to rebalance tariffs within the limit of the rebalancing constraint is not limited by any increase in licence fees. In the above example, the L factor would be added to the CPI+2 per cent rebalancing constraint, to result in an effective CPI+3 per cent rebalancing constraint.[367]

The Commission proposes to incorporate the L-factor in the rebalancing constraint only in those years in which the L-factor is positive. Where the L-factor is negative, this will effectively *increase* the scope under the rebalancing constraint to rebalance tariffs, since all tariffs must fall on average to reflect the lower licence fee, but an individual tariff may still rise up to the limit of the rebalancing constraint. Including the L-factor within the rebalancing constraint in this case would be consistent with ensuring that the L-factor has no impact on the effective ability of the distributors to rebalance tariffs. However, given that the rebalancing constraint is intended to be a back-stop provision limiting the extent of tariff increases faced by any customer in a single year (see discussion in section 4.4), the Commission considers that this objective can be met by maintaining the same limit on tariff increases, but allowing the distributors to take advantage of any implied increase in the scope for relative tariff rebalancing in the event that licence fees are reduced.

The modification to the rebalancing formula proposed in the Draft Decision is discussed in more detail in section 4.4.

With respect to TXU's specific concerns regarding recovery of the 2001-02 licence fees in 2003, the Commission does not consider that this problem arises from the proposed treatment of the licence fee via the L-factor *per se*. Rather, it arises from the interaction between the licence fee increase, the P_0 reduction calculated for TXU and the fixed principle requiring all tariff components to fall by at least 1 per cent in 2003 and hence, gives rise to the 2003 rebalancing constraint proposed by the Commission in its Draft Decision.

[367] The precise formulation of the rebalancing constraint proposed is discussed in section 4.4 and set out in Appendix E.

If the licence fee had been included within the revenue requirement, rather than being passed-through via the L-factor, the P_0 reduction in prices required by the Commission in 2003 would have been less than 1 per cent. This would have led to a similar problem in terms of under-recovery for TXU in that all tariffs are required to fall by at least 1 per cent under fixed principle 10.

In response to Multinet's proposal to replace the terms SR_{t-1} and SR_t with SR_{t-2} in the L-factor formula, the Commission does not believe that such an amendment is required. The rationale behind the L-factor is that it allows the distributor to recover the cost of the licence fees it is required to pay. That is, it is the dollar amount raised via the L-factor that is important, rather than the percentage adjustment allowed. Where the smoothed revenue requirement is increasing, the percentage adjustment required in order to recover the same dollar amount falls. As a result, if the licence fee remains unchanged, it is appropriate for the L-factor to fall in such circumstances. Such a reduction does not imply under-recovery for the distributor.

In relation to the concern raised regarding the time lag between when distributors incur the licence fee costs and when they are able to recover the costs through the L-factor adjustment to tariffs, the Commission agrees to incorporate a mechanism to compensate distributors for the time value of money. Distributors are required to pay their licence fees in one instalment by the end of the financial year to which they relate. Since tariff revenue can be treated as being received, on average, in the middle of the following calendar year (ie. a year later), the appropriate adjustment for the time value of money is (1+pre-tax WACC).

4.2.5 Final Decision

The Commission's Final Decision is to accept the tariff control formula proposed by the distributors, subject to the amendments in relation to the L-factor as noted above, and as outlined in Appendix E.

AMENDMENT REQUIRED

Each of the distributors is required to amend its proposed tariff control formulae as outlined in Appendix E, Boxes E1-E8.

Each of the distributors is required to delete the clause referring to the separate identification of 2003 tariffs.

4.3 Tariff structures

4.3.1 Gas Code requirements

The Gas Code identifies the establishment of efficient tariff structures as a key objective of reference tariffs and reference tariff policy. Specifically, section 8.1(e) of the Gas Code refers to the objective of 'efficiency in the level and structure of the reference tariff.'

4.3.2 Draft Decision

The tariff basket form of price control places a constraint on changes in the weighted average level of tariffs. However, it does not restrict the structure of individual tariffs.

In the Draft Decision, the Commission expressed the view that the distributors should be responsible for determining their own tariff structures, within certain broad upper and lower bound, provided that they comply with the price control formula and any rebalancing constraints. It also required each of the distributors to include a clause to this effect in their Access Arrangements.

In order to provide customers with information on distributors' tariff policies, the Draft Decision also required all distributors to publish an annual tariff report.

4.3.3 Responses to Draft Decision

In response to the Draft Decision, Envestra agreed to include a new clause 3.6 in its Reference Tariff Policy that specified that tariffs would be set between an upper limit of the cost to bypass the network, and a lower limit of the marginal cost of supply.[368]

Both TXU and Multinet agreed to publish an annual tariff report to provide customers with more information on the determination of tariffs. However, both distributors expressed the view that such a report should not be required for 2003 due to the strict control over changes to tariffs in that year.[369]

Envestra argued that an annual tariff report should not be required in any year because the tariff setting process is relatively transparent and it would place an unnecessary administrative burden on distributors.[370]

In response to the Draft Decision, AGL noted that each of the distributors' proposed Revisions have proposed a formula for pro-rating of consumption where a billing period straddles peak and off-peak periods. This has the effect of allocating more GJ into the peak period (where higher distribution tariffs apply) than would otherwise be the case under a simple pro-rata approach.[371] AGL indicated that it did not see the rationale behind this proposal, and that its impact would be to create a mismatch between peak GJ for retail billing and peak GJ for distribution use of system billing. Origin Energy also questioned the allocation formula, and expressed the view that a simple pro-rated allocation is more reflective of actual use.[372] None of the distributors provided a rationale for such an allocation in their submissions.

---

368 Envestra, Response to the Draft Decision, p.15.

369 TXU, Response to Draft Decision, p.20; Multinet Response to Draft Decision, p.91.

370 Envestra, Response to the Draft Decision, p.15.

371 AGL, Response to Draft Decision, p.4.

372 Letter from T. Wood (General manager, Public & Government Affairs, Origin Energy) to J. Tamblyn, (ESC), 24 July 2002, p.3. The relevant provisions are in in Clause 5(2)(B) of the proposed Access Arrangement of each of the distributors.

4.3.4 Further analysis

The Commission notes that all distributors have agreed to include a condition in their Access Arrangements requiring tariffs to at least cover the avoidable cost of providing the service to each customer, but to be below the stand-alone cost to any customer.

The Commission considers that it is important that customers are informed of a distributor's tariff policies, given the discretion that distributors have under the price control formula and rebalancing constraints to determine tariffs. The Commission considers that the distributors' publication of an annual tariff report is an important element associated with ensuring that customers are informed of a distributor's tariff policies. The Commission has previously noted that such a tariff report may include:

- a statement of the distributor's tariffs;
- an outline of the policy framework and tariff principles that the distributor adopted in framing the structure and level of its tariffs;
- an outline of the rationale for introducing new tariffs or closing previously existing tariffs; and
- an explanation of the breakdown between various tariff components.[373]

The Commission therefore welcomes TXU's and Multinet's revised proposal to include the requirement to publish an annual tariff report as part of their Access Arrangements. The Commission does not consider that providing such a report need place a significant administrative burden on distributors. Rather, it views any costs to be outweighed by the value of providing such information to customers. As a result, the Commission remains of the view that Envestra should also be required to provide such a report.

In respect of 2003 tariffs, the Commission is of the view that notwithstanding the fact that the distributors have limited ability to rebalance tariffs in this year there remains a need for the tariff report so as to inform customers of the distributors' tariff principles and policies with respect to existing tariffs.

The Commission notes the concerns expressed by retailers regarding the formula used to pro-rate consumption between peak and off-peak periods. The Commission notes that a similar formula exists in the current Tariff Order and applies when billing periods are greater than or equal to 100 days. In this case, the rationale behind the formula was to provide an incentive for retailers to ensure that there were few lengthy billing periods.[374] An analogous rationale does not appear to arise under the distributors' proposals for pro-rating peak and off-peak consumption.

[373] Position Paper, p.62.

[374] Since the responsibility for meter reading moved from retailers to distributors in September of this year, such a rationale no longer exists. Indeed, the Commission notes that such a provision relating to long billing periods has not been included in the distributors' proposed Revisions for the 2003-07 period.

The Commission sought clarification from the distributors regarding the rationale for the proposed formula.[375] TXU responded by noting that it did not expect the proposed formula to make a difference to the revenue it received.[376] Given the concern expressed by retailers in relation to the formula, and on the basis that TXU noted that there are no implications for revenue, and no further justifications have been offered by the distributors for the proposed formula, the Commission has decided that the formula should be amended to reflect a simple pro-rata approach.

4.3.5 Final Decision

The Commission's Final Decision is that the distributors should be responsible for determining their own tariff structures, within broad upper and lower bounds, provided that they comply with the price control formula and any rebalancing constraints.

In order to provide customers with information on distributors' tariff policies, all distributors should publish an annual tariff report.

AMENDMENT REQUIRED

Envestra is required to amend its proposed Revisions for both Victoria and Albury to include a reference to tariffs being set between an upper limit of the cost to bypass the network and a lower limit of the marginal cost of supply.

Each of the distributors is required to amend its proposed Revisions to indicate that it will publish an Annual Tariff Report.

Each of the distributors is required to amend its proposed formula for calculating charges for haulage reference services when a billing period straddles peak and off-peak periods, so that it reflects a straight pro-rate [Envestra 5(2)(B), TXU 5(2)(B), Multinet 5.2(B)]

4.4 Rebalancing controls

4.4.1 The existing fixed principles

The Gas Code provides that certain principles included in an Access Arrangement may be fixed for a specified period.[377] These principles are not then subject to change when the distributor submits its Access Arrangement for subsequent review. Such principles are known as 'fixed principles.'

375 Email from S. Crees (ESC) to P. Murphy (TXU), 2 September 2002; Email from S. Crees (ESC) to J. Bull (Multinet), 3 September 2002.

376 Email from B. Frewin (TXU) to S. Crees (ESC), 6 September 2002.

377 Section 8.47 of the Gas Code.

In addition to complying with the requirements set out in the Gas Code, each of the distributors' proposals related to tariff structures for the 2003-07 access arrangement period must also comply with the relevant fixed principles in the existing Access Arrangements, with the exception of Envestra (Albury) which does not have any existing fixed principles.

The distributors' existing Victorian Access Arrangements incorporate fixed principles that are set out in section 9.2(b) of the Tariff Order.[378] The relevant fixed principles related to future tariff structures are as follows.

Fixed Principle 10

> Apply the rebalancing formula in Part B of schedule 5 to the tariff components of distribution tariff V, or equivalent distribution tariff applying to small customers receiving tariffed distribution services, with the effect that the distribution tariff V tariff structure will remain in place for the first year of the subsequent access arrangement period, starting at the level at which in real terms it was at the end of the initial regulatory period, and each tariff component will fall in real terms by 1 per cent over that year.

Fixed Principle 9

> Where distribution tariffs which apply in respect of a supply point at which less than 50GJ of gas is supplied annually (in subsequent clauses below, referred to as 'small customers') would rise by a factor greater than CPI over the subsequent access arrangement period, such increase is phased in gradually over the subsequent access arrangement period.

Fixed Principle 4(B)

> When the regulator considers the allocation of costs and tariff design before the start of the subsequent access arrangement period, it will exercise its discretion under sections 8.38 and 8.42 of the Access Code to provide outcomes for distribution tariffs in the subsequent access arrangement period which are consistent with the intent of the public policy adjustments.

4.4.2 Draft Decision

The Commission noted in its Draft Decision that it views rebalancing constraints as a 'backstop' measure to prevent rapid average real tariff increases for specific groups of customers.

The Commission considers that fixed principle 10 requires the existing Tariff V structure to remain in place for 2003, and for there to be a reduction of at least 1 per cent (in real terms) in relation to each of the tariff components.[379]

378 Victorian Gas Industry Tariff Order 1998.
379 This control is set out in clause 9.2(b)(10) of the Tariff Order.

In the Draft Decision, the Commission argued that in the 2004-07 period, restrictions on rebalancing tariffs should be applied at the level of the tariff as a whole, rather than to each tariff component. This is consistent with the approach that the Commission has taken in relation to electricity and allows the distributors greater flexibility in restructuring tariffs, whilst still protecting consumers from rapid tariff increases.

In relation to the magnitude of the rebalancing constraint, the Commission's Draft Decision was that the Y factor included in the rebalancing constraint be set at 0.02 for each distributor. The Commission noted that a control of CPI+2 per cent would be consistent with the rebalancing constraint applying to the electricity distributors, and would therefore provide the same degree of protection to customers of both electricity and gas.

In line with the amendments required in relation to rebalancing constraints, the Commission's Draft Decision also required distributors to include a number of amendments associated with the interpretation of the price and quantity terms in the rebalancing constraints in the event that the distributors proposed to introduce new tariffs or withdraw existing tariffs.

4.4.3 Responses to Draft Decision

Each of the distributors signalled their intention to comply with the rebalancing control formula as outlined above for the 2003 year.[380] TXU acknowledged that its proposed rebalancing of Tariff V in 2003 presented in its earlier Revisions was inconsistent with fixed principle 10 and has subsequently adjusted its proposed tariffs.[381]

As discussed above in section 4.2.3 above, TXU raised the concern that the imposition of the licence fee adjustment proposed by the Commission would mean that it would be unable to recover licence fee costs for the 2001–02 financial year as a result of removing the licence fee from the revenue requirement and imposing the proposed rebalancing constraint for 2003, which requires all tariff components to fall by at least 1 per cent.

TXU noted that, although it maintains its position that no rebalancing constraint is necessary for the 2004-07 period, it recognises the Commission's position that a rebalancing constraint should be implemented for this period in order to meet the requirements of fixed principle 9.[382] Fixed principle 9 relates to the protection of small customers that use less than 50 GJ of gas per annum. Multinet noted that, given the Commission's intention to impose a rebalancing constraint for 2004-07, it should only apply to the segment of end-users that the fixed principles were designed to protect (ie. small customers).[383]

380 TXU, Response to Draft Decision, p.21; Multinet, Response to Draft Decision, p.92.; Envestra response to Draft Decision, p.16.

381 TXU, ibid, p.20.

382 ibid, p.21.

383 Multinet, Response to Draft Decision, p.92.

TXU proposed that small customers with consumption levels lower than 50 GJ per annum should be grouped, and the rebalancing constraint applied to this group only.[384] It noted that it had introduced new Tariff V consumption bands that group small customers in this way. Multinet suggested that small customers could be identified by categorising customers into residential/commercial and metro/rural as required under full retail competition.[385]

Each of the distributors indicated that the rebalancing control of CPI+2 per cent was too restrictive and suggested a more flexible constraint of CPI+5 per cent for Tariff V customers.[386] TXU, Multinet and Envestra all noted that there are significant differences between the markets for electricity and gas that justify imposing a more relaxed rebalancing constraint on gas distributors.[387] Envestra also noted that a more lenient constraint was warranted because the Commission's proposed A-factor and the L-factor may restrict the distributors' ability to rebalance tariffs relative to the X-factor.

Whilst both TXU and Multinet expressed the view that they did not believe that the rebalancing constraint should apply to Tariff D customers, Envestra proposed a more lenient constraint of CPI + 15 per cent for these customers.[388]

In contrast to the position taken by the distributors, AGL welcomed the Commission's proposed rebalancing controls.[389]

Multinet and Envestra both agreed to amend their proposed Revisions to ensure that their proposed Haulage Reference Tariffs comply with the rebalancing control for:

- annual calendar year tariff approvals; or
- changes within the calendar years; or
- new/withdrawn Haulage Reference Tariffs.

TXU made no such agreement in light of the comments made on the proposed rebalancing constraints.[390]

4.4.4 Further analysis

The Commission notes that all distributors have agreed that fixed principle 10 requires the imposition of a rebalancing constraint in 2003. The Commission notes TXU's concern regarding the effect on the rebalancing control in 2003 when the licence fee factor is applied to the price control formula. The Commission is of the view that in order to meet the objective of fixed principle 10, the size of the P_0 adjustment must account for the L-factor. Therefore, the Commission's Final Decision is to set the P_0 adjustment to 2 per cent, based on its estimate that the L-factor is likely to increase average prices in 2003 by 1 per cent.

---

384 TXU, Response to Draft Decision, p.21.

385 Multinet, Response to Draft Decision, p.92.

386 TXU, Response to Draft Decision, p.21; Multinet, Response to Draft Decision, p.92; Envestra, Response to Draft Decision, p.16.

387 ibid., TXU, p.22; Multinet, p.92; Envestra p.16.

388 ibid.

389 Op. cit., AGL, p.3.

390 Op. cit., Multinet, p.94; Envestra, p.16; TXU, p.22.

The Commission acknowledges the distributors' ongoing concerns about imposing of rebalancing constraints over 2004-07.

The Commission's Draft Decision to impose a rebalancing constraint on tariffs over 2004-07 reflected its view that some form of 'back-stop' protection for customers was warranted, in order to prevent rapid average real tariff increases for specific groups of customers. The Commission considers that the move towards more cost-reflective tariffs is desirable, as evidenced by its support for adopting a tariff basket form of price constraint. However, the speed at which such tariff rebalancing takes place should not place undue strain on any one customer group.

The Commission therefore remains of the view that a rebalancing control should apply over 2004-07.

Both TXU and Multinet have suggested that a rebalancing control need only apply to small customers. TXU noted its introduction of a new tariff band for Tariff V customers, which it suggested groups together small customers consuming less than 50 GJ a year. The Commission notes that the new consumption band introduced by TXU covers daily consumption in the range 0-0.137 GJ, for domestic customers. A customer consuming 0.137 GJ a day on each day of the year would have a total annual consumption of 50 GJ. However, customer consumption is not necessarily stable in this way. For example, in the winter period small domestic customers would be expected to increase their gas consumption, as they increased their usage of gas heating appliances. As a result, it is reasonable to expect that there may be cases where a customer consuming less than 50 GJ a year on average, still experiences days within the year when they consume *more* than 0.137 GJ and, hence, when a higher charging band would be applied. As a result, the Commission does not accept TXU's suggestion that applying a rebalancing constraint to only one charging band for Tariff V can adequately protect small customers.

Multinet has proposed that customers be identified as either residential or commercial, via the same processes that apply for FRC.[391] The implementation of this proposal also appears to be difficult practically, given that the same tariffs currently apply to both residential and commercial customers.

The distributors' broader proposals that rebalancing constraints only apply to Tariff V or (in the case of Envestra) that different rebalancing constraints apply to Tariff V and Tariff D, fails to consider the practical application of the constraint in the event that new tariffs are introduced. Under the price control arrangements included in the Access Arrangement Revisions, distributors are free to introduce new tariffs. Given that Tariff V customers account for approximately 50 per cent of gas demand and contribute towards 95 per cent of distributors' total revenue, it is likely that the introduction of a new tariff would draw customers from this tariff group to the new tariff. If the rebalancing constraint were only applied to Tariff V, as suggested by TXU and Multinet, small customers that were attracted to any new tariff introduced by the distributors would no longer receive protection from the rebalancing constraint. The Commission is of the view that applying the rebalancing constraint to all tariffs provides greater transparency and greater certainty than a process whereby the appropriate constraint is considered separately for each new tariff, as the need arises.

[391] Op. cit., Multinet, p.92.

In relation to the magnitude of the rebalancing constraint that should apply for the 2004-07 period, the Commission is of the view that the strictness of the rebalancing constraints that were applied in the past is not a relevant consideration in determining the ‘back-stop’ protection that should now be provided to customers. Indeed, to the extent that the previous tight controls have resulted in current tariffs not being cost reflective, resulting in a real likelihood of distributors seeking to rebalance tariffs more rapidly in the current access arrangement period, then that would appear in itself to be justification for providing a degree of customer protection from rapid increases through the rebalancing constraints.

TXU and Multinet have both expressed the view that there are differences between the electricity and gas markets that would support a more relaxed rebalancing constraint for gas than the CPI+2 per cent constraint applied to electricity. In particular, gas is viewed as a non-essential service, and has a higher price elasticity of demand. Whilst the Commission agrees that gas is generally viewed as a ‘fuel of choice’ for domestic customers, once customers *have* decided to utilise gas as a source of energy, they are likely to be “locked in” for a period of years to the extent that they then face switching costs (in the form of changing appliances) if they later wish to change their decision. This is likely to reduce the price elasticity of demand for gas in the short-term. As a result, small domestic customers currently using gas might be disadvantaged by a rapid increase in its price, as their flexibility to change energy sources in the short-term is likely to be constrained.

In addition, to the extent that there is a relatively high price elasticity of demand for gas, the Commission would expect that this would in itself place a limitation on the speed with which distributors would wish to rebalance their charges. In that sense, the rebalancing constraint imposed by the Commission would indeed be a ‘back-stop’.

As a result, the Commission’s Final Decision is that it is appropriate to apply a rebalancing constraint of CPI+2 per cent applied at the tariff level for the 2004-07 period.

Notwithstanding this view, the Commission notes the concern expressed by distributors that applying the L-factor (to allow recovery of licence fees) and the A-factor (in 2004, to allow for any under- or over-recovery of the correction factor) will restrict the effective rebalancing which can be achieved under the rebalancing control. As a result, the Commission proposes that, in years where the L-factor and/or the A-factor is positive, these factors are added to the rebalancing constraint. The result of this proposal is that the distributors will have the ability to rebalance by the same amount in relation to the X-factor in all years, regardless of the changes in licence fees or the A-factor. These formulae are detailed in Appendix E, Boxes E.9 and E10.

4.4.5 Final Decision

Pursuant to the requirements of the Tariff Order, the Commission requires each of the distributors to amend their proposed Revisions in order to incorporate the rebalancing controls outlined above, and as contained in Appendix E, Boxes E.9-E10.

AMENDMENTS REQUIRED

Each of the distributors is required to amend its proposed Revisions to incorporate the rebalancing control formula, as outlined in Appendix E, Boxes E9-E10.

Each of the distributors is required to amend its proposed Revisions to require the Service Provider to ensure that its proposed Haulage Reference Tariffs comply with the rebalancing control for:

- **annual calendar year tariff approvals; or**
- **changes within the calendar years; or**
- **new/withdrawn Haulage Reference Tariffs.**

Each of the distributors is required to amend its proposed Revisions to provide that where the distributor proposes to introduce a new Haulage Reference Tariff and/or new Haulage Reference Tariff components:

- **the term q_{t-2}^{j} in the rebalancing control will be interpreted in relation to the estimates of the quantities that would have been sold, in relevant units, if the Haulage Reference Tariff components had existed in calendar year t-2; and**
- **the p_{t}^{j} term in the rebalancing control will be interpreted in relation to the Haulage Reference Tariff components of the parent tariff in calendar year t-2.**

Each of the distributors is required to amend its proposed Revisions to provide that where the distributor has introduced a new Haulage Reference Tariffs and/or new Haulage Reference Tariff components in calendar year t-1, the q_{t-2}^{j} term in the rebalancing control will be in relation to the estimates of the quantities that would have been sold, in relevant units, if the Haulage Reference Tariff components had existed in calendar year t-2.

Each of the distributors is required to amend its proposed Revisions to provide that where the distributor proposes to withdraw a Haulage Reference Tariff and reassign those existing distribution customers to another Haulage Reference Tariff:

- **the p_{t}^{j} term in the rebalancing control for the Haulage Reference Tariff that is proposed to be withdrawn will be interpreted in relation to the Haulage Reference Tariff components of the Haulage Reference Tariff that those existing Distribution Supply Points will be reassigned to in calendar year t;**
- **the rebalancing control on Haulage Reference Tariffs will be applied separately in relation to each of the Haulage Reference Tariffs Distribution Supply Points are reassigned to, and:**

(a)	**the p_t^j term in the rebalancing control for the Haulage Reference Tariff that is proposed to be withdrawn will be interpreted in relation to the Haulage Reference Tariff components of each of the Haulage Reference Tariffs that those existing Distribution Supply Points will be reassigned to in calendar year t; and**
(b)	**the q_{t-2}^j term in the rebalancing control for the Haulage Reference Tariff that is proposed to be withdrawn will be the breakdown of the actual quantities, in relevant units, that were sold under each Haulage Reference Tariff component of the parent tariffs to each Distribution Supply Points reassigned to the same Haulage Reference Tariff.**

4.5 Treatment of the correction factor from 1998-2002

4.5.1 Gas Code requirements

As noted above, the Gas Code provides for fixed principles to be included in Access Arrangements. The existing Access Arrangements incorporate a fixed principle which in effect requires the Commission, in deciding whether to approve the proposed Revisions for the 2003-07 regulatory period, to have regard to the correction factor (known as the KDt factor) calculated for each distributor for the last year of the current access arrangement period.[392] The correction factor reflects the difference between the amount of revenue the distributor is permitted to earn under the form of price control applying in the 1998-2002 access arrangement period and the actual amount of revenue the distributor earns.

4.5.2 Draft Decision

In the Draft Decision, the Commission proposed that an estimate of the KDt correction factor associated with operating the revenue yield form of price control in the 1998-2002 access arrangement period should be included in the distributor's revenue requirement in the 2003-07 access arrangement period. Further, it proposed that a 'truing-up' for the difference between the actual KDt factor and the estimated factor be made via an adjustment to 2004 tariffs.

This approach to recovering the KDt factor avoids concentrating the impact of the adjustment on prices in a single year. The Commission proposed that distributors would recover the KDt revenue over the course of the 2003-07 access arrangement period (rather than solely in one year), and so smooth the price impact on customers. The 'truing up' between the actual KDt factor and the estimated factor would take place via the inclusion of an adjustment factor (A) in the price control formula in 2004.

392 Victorian Gas Industry Tariff Order 1998, section 9.2(b)(7).

4.5.3 Responses to Draft Decision

In its response to the Commission's Draft Decision, TXU agreed to amend its proposed adjustment factor to ensure that it only reflects the difference between the estimated and actual KDt factor for 2002, and to include the estimate of the KDt factor in the revenue requirement.[393] TXU also agreed that the adjustment factor A applied in 2004 should be divided by a forecast of smoothed revenue so that it can be incorporated into the price control formula.

Multinet also agreed that the A factor should only reflect the difference between the estimated and actual KDt factor for 2002. However it suggested that the A factor should remain outside the rebalancing constraint, as including it within the constraint may cause the constraint to bind, affecting the ability of the distributor to recover this amount.[394] If the rebalancing constraint were to be applied to tariffs including the A factor then Multinet's view is that the magnitude of the constraint would need to be revised.

Envestra agreed to the general principle that tariffs should be adjusted in 2004 to reflect the difference between the expected and actual KDt factors for 2002.[395] However, it also expressed the view that the mechanism for incorporating the KDt factor should allow the company to recover the entire amount post-tax. Envestra does not believe that the approach adopted by the Commission in its model will produce this result.

4.5.4 Further analysis

The Commission notes that all of the distributors have accepted the Commission's overall proposed approach to the treatment of the KDt factor.

Table 4.1 presents the Commission's estimate of the KDt factors applying to each distributor for 2002.[396] These estimates are the same as those presented in the Draft Decision and are based on the distributors' projections of 2002 demand at the time at which their 2002 tariff proposals were lodged with the Commission**.** Since there will be an eventual 'truing-up' between this estimate and actual outturn demand, the Commission does not consider it necessary to update these demand estimates for the purposes of calculating the KDt factor.

---

393 TXU Response to Draft Decision, p.24.

394 Op. cit., Multinet, p.94.

395 Op. cit., Envestra, p.17.

396 These have been calculated by multiplying the difference between the $MADT_{2002}$ and $FADT_{2002}$ by the forecast of GJ to be sold in 2002 submitted by the distributors at the time at which their tariffs for 2002 were lodged.

TABLE 4.1
ESTIMATED KDT FACTOR FOR 2002

Distributor	KDt ($ million)
Envestra – Albury	Not applicable
Envestra – Victoria	0.6
Multinet	5.7
TXU	2.8

The Commission has included the above KDt amounts in calculating the revenue requirement for each of the distributors (see section 3.10).

In relation to adjusting 2004 tariffs to account for the difference between the estimated KDt factor included in table 4.1 and the actual outturn, the Commission notes Multinet's concern regarding the impact on the effective scope for rebalancing under the rebalancing constraint. As a result, the Commission has amended its proposal for the form of the rebalancing constraint in 2004 to include the A-factor (see section 4.3).

The Commission notes that, since the 2004 tariff adjustment is a once-off adjustment in order to allow for any difference between the estimated KDt factor for 2002 and the actual KDt factor, the A factor needs to be included in the denominator of the price control factor for 2005 in order to remove the impact of the adjustment on tariffs in the years after 2004.

4.5.5 Final Decision

The Commission's Final Decision is that the estimate of the KDt correction factor presented in table 4.1 be included in the distributors' revenue requirement in the 2003-07 access arrangement period, and that a 'truing-up' for the difference between the actual KDt factor and the estimated factor be made via an adjustment to 2004 tariffs. To give effect to this Final Decision, the Commission requires the distributors to make the following amendments.

AMENDMENTS REQUIRED

TXU and Multinet are each required to amend their proposed Revisions such that the adjustment amount *(A)* applied to reference tariffs in 2004 reflects only the difference between the estimated and actual KDt factor for 2002 as set out in Appendix E, Boxes E2 & E5-E8.

Envestra is required to include in its proposed revisions for Victoria a provision that allows tariffs to be adjusted in 2004 to reflect the difference between it's estimated and actual KDt factor for 2002 as set out in Appendix E, Boxes E2 & E5-E8.

Each of the distributors is required to include an adjustment to the price control formula in 2005 that reverses the impact of the A-factor as set out in Appendix E, Boxes E3 & E5-E8.

4.6 Recovery of FRC costs for the Albury network

The Commission's Draft Decision noted that the FRC costs incurred by Envestra in relation to its Albury network should be recovered on a similar basis as the recovery of FRC costs for Envestra's Victorian network. That is, there should be a separate reference tariff component for FRC cost-recovery levied on customers in Envestra's Albury network, which sits outside the main distribution price control applied to haulage reference tariffs. The basis for this separate FRC charge should be consistent with the decisions made under the Order in Council in relation to the recovery of FRC related charges. Decisions in relation to the Order in Council had not been made at the time of the Draft Decision.

Envestra noted in its response to the Draft Decision that it accepts this amendment and will provide the Commission with a proposal setting out the separate tariffs to apply to recover FRC costs in Albury in due course.[397] Envestra also noted that whilst the tariff has not yet been determined, it anticipates that the unit costs in relation to Albury customers will be the same as those applying to regional customers in Victoria.

4.6.1 Order In Council Decision

In August 2002, the Commission released its Final Decision under the Order in Council in relation to the recovery of FRC costs for Envestra's Victorian network for the period 1 October 2002–31 December 2003. Under this decision, the recommended tariffs for Envestra's Victorian network are:

- a customer supply point charge of $963.83/annum; for customers consuming above 5 000GJ/annum;
- a fixed customer charge of $7.725/annum; for customers consuming less than 5 000GJ/annum; and
- a low usage volume charge of $0.1928/GJ for customers consuming less than 5 000GJ/annum.

Under the Order in Council Decision, there will be an annual adjustment process to account for any over-or-under recovery of charges, based on actual data to end-August each year. The distributors will be required to submit data on actual costs by 1 October each year. The required adjustment will be made to tariffs from the beginning of January the following year, commencing in January 2004**.**

In deriving the tariffs for Envestra's FRC cost recovery, the Commission excluded from the amount of total costs submitted by Envestra, an amount corresponding to the costs associated with the Albury network. This amount was worked out on a pro-rata basis, based on customer numbers in the Albury area as a proportion of total customer numbers. This approach implicitly assumes that the costs per customer for the Albury network will be similar to the costs incurred per customer for its Victorian network. This is consistent with Envestra's position as expressed in its response to the Draft Decision.

397 Envestra, Response to Draft Decision, p.17.

Given the above, the Commission considers it appropriate for the reference tariff component for the recovery of Envestra's FRC costs to be set equal to the tariffs determined under the Order in Council process for Envestra's Victorian network. That is, in addition to the tariffs determined for Envestra in line with the price control formula, the Commission will allow Envestra to levy a tariff that matches that determined under the Order in Council process for its Victorian network.

The Commission notes that its Final Decision on the Order in Council permits Envestra (Victoria) to levy the FRC charge noted above from 1 October 2002 to 31 December 2003. For Albury, Envestra will only be permitted to levy a charge from 1 January 2003, for that calendar year (ie. a three month difference). As a result, the Commission considers it appropriate to scale the charges applying to Envestra's Albury network upwards by a factor of 15/12, to take into account the shorter time period over which the tariffs will apply, before being reviewed. That is, from 1 January 2003 to 31 December 2003, Envestra is permitted to levy the following charge:

- a customer supply point charge of $1 204.79/annum; for customers consuming above 5,000GJ/annum;
- a fixed customer charge of $9.656/annum; for customers consuming less than 5 000GJ/annum; and
- a low usage volume charge of $0.241/GJ for customers consuming less than 5 000GJ/annum.

From 1 January 2004 onwards, Envestra is permitted to levy a charge equal to that determined as applicable for that year by the Commission under the Order in Council for Envestra's Victorian network.

Envestra is required to amend its proposed Revisions to incorporate the above provisions.

AMENDMENT REQUIRED

Envestra is required to amend its proposed Revisions for Albury to include a separate Reference Tariff component outside of the main distribution price controls applying to Haulage Reference Tariffs that provides for the recovery of its costs of implementing FRC.

Specifically, Envestra is required to include a provision which states that it will charge the same tariffs for cost-recovery of FRC as those determined for its Victorian network by the Commission under the Order in Council, with the exception that, for the 2003 calendar year, these tariffs will be:

- **a customer supply point charge of $1,204.79/annum; for customers consuming above 5,000GJ/annum;**
- **a fixed customer charge of $9.656/annum; for customers consuming less than 5,000GJ/annum; and**
- **a low usage volume charge of $0.241/GJ for customers consuming less than 5,000GJ/annum.**

4.7 Reference tariff approval and variation processes

4.7.1 Draft Decision

In the Draft Decision, the Commission expressed the preliminary view that the distributors' proposed processes for varying reference tariffs were largely appropriate. However, it also highlighted a small number of issues that it considered the Access Arrangements should also address.

In particular, the Commission required each of the distributors to include in their reference tariff policy clauses that deal with the following matters:

- how reference tariffs will be adjusted at the commencement of each calendar year where the distributor has not submitted reference tariffs for approval;
- a requirement that all quantity data submitted with their annual reference tariff proposals be independently verified;
- a requirement that new reference tariffs be submitted to the Commission at least 60 business days prior to the commencement of the next calendar year; and
- a formula for determining how ancillary reference services are to be adjusted on an annual basis.

In relation to the provisions that would apply if the distributors did not submit reference tariffs for approval, the Commission's Draft Decision was to the effect that:[398]

- if $(1+CPI_t)(1-X_t) > 1$, the Haulage Reference Tariffs applying in Calendar Year t-1 would continue to apply; or
- if $(1+CPI_t)(1-X_t) < 1$, the Haulage Reference Tariffs applying in Calendar Year t-1 would be scaled down by $(1+CPI_t)(1-X_t)(1+L_t)$ and apply from the start of Calendar Year t.

[398] The formulae presented in the Draft Decision were incorrect, and were subsequently clarified as part of the consultation process. The correct formulae are set out in Appendix E.

4.7.2 Response to Draft Decision

All of the distributors agreed to include a clause in the proposed Revisions setting out what would happen in the event of a distributor not submitting a proposal to vary reference tariffs for the upcoming calendar year.[399] Each of the distributors accepted the Commission's proposal that, where tariffs have not been submitted and where the increase in CPI is less than the X factor, then the reference tariffs applying in year t-1 should be scaled down by the factor (1+CPIt)(1-Xt)($1+L_t$). However, the distributors proposed that a symmetrical approach be taken, which would result in the scaling up of reference tariffs by the same factor in the case where tariffs are not submitted and the increase in CPI is greater than the X factor. The distributors expressed the view that such a symmetrical approach would not disadvantage a company that was not able to submit its proposal for tariff variation due to the occurrence of an unexpected or unavoidable event.

None of the distributors agreed with the proposed requirement to have quantity data independently verified prior to submission of a tariff proposal.[400] Such verification was considered unnecessary due to current external audit requirements under company law and the Commission's existing powers to conduct audits. Multinet expressed the view that independent verification should be restricted to new tariffs and tariff components.[401]

All of the distributors argued that if the requirement for independent verification of quantity data is enforced, the cost of obtaining such verification should be taken into account in the overall revenue requirement.[402]

Both Multinet and Envestra agreed to the requirement for new reference tariffs to be submitted to the Commission at least 60 business days prior to the commencement of the next calendar year.[403] TXU made no comment on this issue.

Each of the distributors agreed to include in their proposed Revisions the Commission's proposed formula for adjusting ancillary reference tariffs.[404]

4.7.3 Further analysis

The Commission notes that all of the distributors have agreed to include clauses in their proposed Revisions that set out the tariffs that would apply in the event that a distributor failed to propose tariffs for the next calendar year.

---

399 TXU, Response to Draft Decision, p.24; Multinet, Response to Draft Decision, p.97; Envestra, Response to Draft Decision, p.17.

400 ibid., TXU, p.25; Multinet, p.97; Envestra, p.18.

401 Multinet, Response to Draft Decision, p.97.

402 TXU, Response to Draft Decision, p.25; Multinet, Response to Draft Decision, p.96; Envestra, Response to Draft Decision, p.18.

403 ibid., Multinet, p.97; Envestra, p.18.

404 ibid., TXU, p.25; Multinet, p.98; Envestra, p.18.

The Commission does not accept the view that a symmetrical approach should be taken in determining tariffs at times when a distributor itself does not submit reference tariffs for approval. Scaling *down* the tariffs applying in the current calendar year when the increase in CPI is less than the X factor, provides the distributor with an incentive to lodge tariff proposals for the upcoming year. A symmetrical approach would require the scaling *up* of tariffs, in situations where the increase in CPI was greater than the X-factor. However, a default clause that increased tariffs in this way would not provide a strong incentive for distributors to lodge tariff proposals before the due date. In contrast, by specifying that reference tariffs will not change until a proposal is submitted, the Commission is ensuring that distributors will make every effort possible to prepare and lodge any proposed amendments to tariffs on time.

The Commission does not consider it likely that distributors will find themselves in circumstances that would prevent them from lodging tariff proposals by the due date. As a result, its considered view is that the incentive properties associated with not scaling up tariffs, in the event that the distributor fails to lodge tariff proposals, outweigh any risks faced by the distributors in not being able to lodge tariffs.

The Commission notes that it must consider all of the factors applicable to the price control formula when deciding what to do if a distributor fails to submit its proposed tariffs, this includes the L-factor and A-factor outlined above.

As a result, the Commission's Final Decision with respect to what would apply in the event that a distributor failed to propose tariffs for the next calendar year is :

- if the left-hand side of the price control formula is greater than one, the Haulage Reference Tariffs applying in Calendar Year t-1 will continue to apply; and
- if the left-hand side of the price control formula is less than one, the Haulage Reference Tariffs applying in Calendar Year t-1 will be scaled down by the left-hand side of the price control formula, and apply from the start of Calendar Year t.

With respect to the requirement for quantity data to be independently verified, the Commission notes that if an external audit process has already been conducted, this verification would be sufficient in relation to past quantities sold, and no additional cost should be incurred by the distributors in order to meet this requirement.

The Commission notes that there may be an issue with the timing at which such audit data is available, relative to the time at which tariff proposals are submitted, given that the former will ordinarily be conducted on the company's financial year basis and the latter on a calendar year basis. However, the Commission notes that, even if final audited quantity data was not available for the latter part of the period, data would be available for the first part and could usefully be provided in support of the quantity data submitted.

The Commission wishes to avoid imposing onerous reporting requirements on the regulated businesses, where possible. The Commission has therefore decided to remove the proposed requirement on distributors to submit audited quantity data as part of their tariff proposals. However, the Commission notes that, if it continues to have concerns regarding the veracity of reported quantity data at the times at which tariffs are being approved, it will seek further information from distributors in support of the quantity data submitted.

In situations where new tariffs are being introduced, the Commission recognises that audit data will not be sufficient to provide independent verification. However, the distributors are required to explain the basis for estimates of the quantities that would have been sold in such circumstances. The Commission is of the view that independent verification is the best way to achieve this.

The Commission notes Multinet's and Envestra's acceptance of the amendment to submit information on new tariffs at least 60 days before the proposed introduction of such tariffs. The Commission notes that, where new tariffs are being introduced in respect of a new calendar year, the distributors will not have information on CPI on which to base their final tariff proposals. However, it continues to be of the view that there is value in providing information on the proposed change (including, but not limited to, the type of change envisaged), prior to the precise tariffs being verified, in order to allow time for the changes to be considered by customers and to make any necessary adjustments to their systems.

4.7.4 Final Decision

The Commission requires each of the distributors to include in their reference tariff policy clauses that deal with the following matters:

- how reference tariffs will be adjusted at the commencement of each calendar year where the distributor has not submitted reference tariffs for approval;
- a requirement that all quantity data submitted with their annual reference tariff proposals be independently verified;
- a requirement that new reference tariffs must be submitted to the Commission at least 60 business days prior to the commencement of the next calendar year; and
- a formula for determining how ancillary reference services are to be adjusted on an annual basis.

AMENDMENTS REQUIRED

Each of the distributors is required to include the following clauses in their proposed revisions:

If the Service Provider does not submit proposed Haulage Reference Tariffs in accordance with clause 4.1(a), then

- **if the left-hand side of the price control formula is greater than one, the Haulage Reference Tariffs applying in Calendar Year t-1 will continue to apply; or**
- **if the left-hand side of the price control formula is less than one, the Haulage Reference Tariffs applying in Calendar Year t-1 will be scaled down by the left-hand side of the price control formula, and will apply from the start of Calendar Year t.**

Where the Service Provider proposes to introduce a new Haulage Reference Tariff or new Haulage Reference Tariff Component, it is required to submit proposed new Haulage Reference Tariffs or new Haulage Reference Tariff Components at least 60 business days prior to the date on which it wishes the new tariffs to commence.

The Ancillary Reference Tariffs, as set out in Schedule 2, will be adjusted by the formula outlined in Appendix E, Box E13 of this Final Decision.

4.8 Change in tax pass through provisions

A ‘change in tax pass-through’ typically applies when a regulated business faces an increase in costs arising from the introduction or change of a tax imposed on the service provider that was not foreseen at the time at which reference tariffs were set. Such a situation is termed a ‘change in tax event’. The result of allowing a change in tax pass-through is that a business may increase or decrease reference tariffs in line with the approved amount of the increased or decreased costs associated with the new or amended tax.

Currently, section 7 of the Tariff Order sets out the process by which distributors may seek a pass-through of costs associated with a change in tax event and defines certain terms such as a ‘change in taxes event’ and ‘relevant tax’. These provisions will cease to have effect on 31 December 2002.

The distributors’ proposed Revisions largely adopted the current Tariff Order pass-through arrangements. In particular, the distributors’ proposed Revisions provide that wherever a service provider determines that its costs have increased or decreased materially as a result of a new relevant tax or a change in a relevant tax, the service provider may apply to the regulator for approval to increase or decrease its reference tariffs in accordance with the procedures set out in the proposed Revisions.[405]

[405] Envestra (Victoria and Albury), TXU and Multinet, Reference Tariff Policy, Clause 8.

However, there are a number of important differences between the current Tariff Order provisions and those proposed by the distributors in their Revisions, namely:

- the definitions applied to the terms 'change in taxes event' and 'relevant tax' differ significantly from the existing Tariff Order definitions; and
- Envestra has proposed a notification period of 12 months in contrast to the 3 months proposed by the other distributors (and currently provided for in the Tariff Order).

In their proposed Revisions, each of the distributors adopted the definition of a 'change in taxes event' as follows:

> A variation, withdrawal or introduction of a relevant tax, or a change in the way or rate at which a relevant tax is calculated, *or a cost incurred under paragraphs (a) and (b):*
>
> (a) any cost, expense or other amount of any nature whatsoever which the Service Provider is directed, ordered or required to incur by any Authority in respect of the repair, maintenance, administration or management of the Distribution System (or any part of it) or in respect of the provision of Reference Services (including, but without limitation, any costs, expenses or other amounts the Service Provider is directed, ordered or required to incur in remediating sites associated (or historically associated) with the Distribution System that have been or are polluted or contaminated); and
>
> (b) any costs, expense or other amount of any nature whatsoever which the Service Provider incurs in complying with (or attempting to comply with) any direction, order or requirement of any Authority or any change in a Regulatory Instrument in or in respect of the repair, maintenance, administration of management of the Distribution System (or any part of it) or in respect of the provision of Reference Services. [emphasis added][406]

In addition, the distributors have each defined a 'relevant tax' in the proposed Revisions as:

> Any royalty, duty, excise, tax, impost, levy, fee or charge (including, but without limitation, any GST) imposed by an Authority in respect of the repair, maintenance, administration or management of the Distribution System (or any part of it) or in respect of the provision of the Reference Services.
>
> This definition is considerably wider than that in the Tariff Order, which contains a number of specific exclusions.

4.8.1 Draft Decision

In the Draft Decision, the Commission expressed the view that the distributors' proposed definitions of a change in tax event and relevant tax were too broad, and in particular provided scope for distributors to seek pass-through for a broad range of 'costs or expenses' that are not contemplated by the current Tariff Order provisions. It argued that this has a number of disadvantages:

---

[406] Envestra's definition does not include the reference within the brackets at the end of (a) to remediation costs.

- it reduces incentives for distributors to minimise costs that are potentially within their control and instead provides them with an incentive to seek to pass-through those costs (and thereby increase reference tariffs);
- it increases the costs of administering the pass-through provisions for distributors, users and the Commission as a result of the need to consult on an increased potential number of pass-through claims; and
- it reduces certainty for users about the reference tariffs that are to apply over the period.

Accordingly, the Commission proposed that each distributor should amend its proposed pass-through provisions to give effect to the relevant definitions under the Tariff Order.

In addition, the Commission required Envestra to amend its proposed Revisions for both Victoria and Albury to provide notice of a change in tax event to the Commission within a period of 3 months rather than 12 months. In doing so, the Commission expressed the view that individual distributors should not be procedurally advantaged or disadvantaged as a result of differences in the timelines provided for in their respective Access Arrangements and that it was desirable to ensure that the processes and timelines applying to each distributor in relation to change in tax pass-through provisions were consistent.

The Draft Decision also required each of the distributors to insert a provision allowing the Commission to initiate a change in tax pass-through.

4.8.2 Responses to Draft Decision

In response to the Draft Decision, the distributors argued that the current pass-through provisions in the Tariff Order (particularly the definition of a relevant tax) are overly restrictive and fail to consider items that are not within a distributor's control.[407] As a result, they argued that they were exposed to risks that they should not be required to bear. Multinet noted that the Tariff Order definitions were particularly restrictive when compared with definitions used in similar regulatory instruments in other jurisdictions.

Envestra expressed the view that its proposed tax pass-through provision provided a fair and reasonable mechanism that ensures that it is not penalised for risks associated with events outside its control, including additional service level or regulatory requirements (eg. increases in service standards) imposed after the approval of its Revisions and changes in other non-controllable factors such as taxes.

[407] Multinet, Response to Draft Decision, p.109. TXU, Response to Draft Decision, p.40, Envestra, Response to Draft Decision, p.20.

In addition, the distributors argued that the proposed clause would result in minimal additional uncertainty being provided to users. Envestra argued that uncertainty already exists in relation to matters such as inflation, rebalancing, licence fees (the proposed L factor), the ability to introduce new tariffs and the K factor adjustment and that the broader change in tax pass through provisions were simply an extension of the Commission's approach to the pass-through of uncontrollable items such as licence fees (through the L factor).[408]

Notwithstanding the above points, each of the distributors indicated that they were prepared to amend the definition of a change in tax event to address some of the Commission's concerns.

Multinet agreed to amend the definition of 'Change in Taxes Event' by deleting reference to paragraphs (a) and (b), resulting in the following definition:

> Change in Taxes event means a variation, or withdrawal or introduction of a Relevant Tax, or a change in the way or rate at which a Relevant Tax is calculated.[409]

Both Envestra and TXU indicated that they were prepared to amend the change in tax event definition to remove the number and scope of pass-through items and introduce a materiality restriction in order to minimise administrative costs associated with the arrangements. Envestra proposed the following alternative definition:

> Change in Taxes Event means a variation withdrawal or introduction of Relevant Taxes, or a change in the way or rate at which Relevant Taxes are calculated, which will increase or decrease Envestra's costs by more than $50 000 per annum.[410]

TXU did not set out the nature of its proposed wording.

None of the distributors proposed a change to their definition of Relevant Tax.

Envestra has proposed not to amend the clause requiring it to provide notice of a change in tax event to the Commission within a period of 3 months rather than 12 months. Envestra argued that the Commission has given no reason why a 3-month period for notice of a change in tax events is superior to 12 months. In contrast, it believes that a 12-month period allows:

- Tax pass-through to be considered concurrently with the annual price review process;
- More time for the business to understand the impact of the tax change and the way in which it should be factored into tariffs. This is particularly the case where taxes are changed with little public notice, or where the effect on costs is uncertain; and

> Multiple tax changes to be 'bundled up' and processed at the same time, resulting in some administrative savings to both the distribution business and the regulator.[411]

408 ibid., Envestra, p.20.
409 ibid., Multinet, Response to Draft Decision, p.109.
410 ibid., Envestra, p.21.
411 ibid., Envestra, p.21.

Finally, in commenting on the Commission's proposal for the distributors to insert a provision allowing the Commission to initiate a change in tax pass-through, all distributors commented that such an amendment does not appear to be necessary, as clause 8.3 of their reference tariff policies already allows for the Commission to initiate a change in tax pass-through.

4.8.3 Further analysis

Change in tax event

The Commission notes that all of the distributors have proposed revisions to their earlier definitions of a 'change in tax event'.

The distributors have commented that their revised definition reduces the number and scope of pass-through items. The Commission acknowledges that the changes that the distributors now propose have the potential to reduce the number and scope of pass-through items. However, whether an event qualifies as a pass-through event will depend on the definition of Relevant Tax. The scope for pass-through events under the revised definition proposed by distributors is therefore dependent on the scope of the definition of Relevant Tax (discussed below).

Both TXU and Envestra have proposed that a threshold should be specified in the change in tax event definition to minimise the administrative costs associated with the change in tax pass through arrangements. In particular, Envestra has proposed to amend the change in tax definition to provide that a change in tax pass through can be sought only if its costs are likely to increase or decrease by more than $50 000 per annum.

The Commission notes that each of the distributors have included in clause 8 of their proposed Revisions a statement that the service provider may apply for a change in tax pass-through only where it determines that its costs will increase or decrease *materially* as the result of a new Relevant Tax, or a change in a Relevant Tax.

The Commission agrees that there should be a materiality test for proposed pass-through events and, in particular, that the impact of the change in tax event should be significantly greater than the administrative costs involved in determining the appropriate pass-through amount.

However, the Commission believes that the current statement of materiality is sufficient for this purpose, and that it is not necessary or desirable to specify a threshold amount as part of the definition of a change in tax event. However, the Commission notes that providing guidelines on what it is likely to consider to be a 'material impact' may be desirable going forward, in order to provide greater clarity to distributors. The Commission therefore proposes to consult on and provide such guidelines, separately from this Final Decision. The Commission notes that the $50 000 cost threshold proposed by Envestra represents less than 0.05 per cent of its annual revenue requirement.

The Commission notes that, although the requirement for a change in Relevant Taxes to have a material impact on the distributors' costs is included in the distributors' proposed Revisions, it is not explicitly reflected in the definition of a Change in Taxes Event. In contrast, the definition of change in taxes event included in the current Tariff Order clearly links a change in taxes event to the impact on the distributors' costs. In addition, given that Reference Tariffs apply to Reference Services, the Commission considers it appropriate to clarify within the definition of a change in taxes event, that such an event must impact the costs to the distributor of providing the *Reference Services* (rather than non-reference services). Again, this reflects the current definition of 'change in taxes event' in the Tariff Order.

As a result, the Commission's Final Decision is that the definition of a 'change in taxes event' for all distributors should be amended as follows:

> Change in Taxes event means a variation, or withdrawal or introduction of a Relevant Tax, or a change in the way or rate at which a Relevant Tax is calculated, *which has a material impact on the costs to the distributor of providing the Reference Services.* (emphasis added)

Relevant tax

In relation to the definition of a relevant tax, the Commission notes that each of the distributors have proposed the same definition, which provides for pass through of:

> 'any royalty, duty, excise, tax, impost, levy, fee or charge (including, but without limitation, any GST) imposed by an Authority in respect of the repair, maintenance, administration or management of the Distribution System (or any part of it) or in respect of the provision of the Reference Services'.

As noted above, this definition is considerably wider than that included in the current Tariff Order, which contains a number of explicit exclusions.

The Commission notes the distributors' concerns regarding the restrictive nature of the current Tariff Order provisions, and the extent to which the current definition exposes them to changes in costs that are not under their control.

The Commission agrees that some of the exclusions under the definition of Relevant Taxes in the Tariff Order would capture charges which are outside of the distributors' control, and which are likely to impact on their costs. As a result, the Commission sees merit in widening the definition of Relevant Taxes from the current Tariff Order definition, to limit the risks faced by the distributors from factors outside of their control. However, the Commission continues to have concerns about allowing too great a scope for the businesses to pass-through costs, particularly to the extent that this results in items that are potentially under the distributors' control being captured under the definition. In addition, the greater the number of potential pass-through items, the higher the administrative burden (and therefore cost) implied for both distributors and the Commission.

The Commission therefore considers that it is necessary to find a balance between the costs and benefits of allowing the distributors to pass-through changes in costs under the changes in tax provisions.

The Commission believes that it is appropriate to exclude from the definition of Relevant Taxes the following (in line with the current Tariff Order definition):

(1) income tax (or State equivalent income tax) and capital gains tax;

(2) fees and charges payable for distribution licences or any other membership, contribution or other charge payable to other regulatory bodies in the gas industry;

(3) stamp duty, financial institutions duty, bank accounts debit tax or similar taxes or duties;

(4) penalties and interest for late payment relating to any tax, royalty, duty, excise, impost, levy, fee or charge; and

(5) any tax or charge which replaces the taxes and charges referred to in (1) to (4).

The Commission notes that this list of exclusions is considerably shorter than those in the current Tariff Order definition of Relevant Taxes.

The impact of income tax, capital gains tax and changes in taxes relating to financial transactions depend on projections of the profitability and associated cash-flow of the distribution businesses. As such, an assessment of the impact and the appropriate pass-through amount would necessitate a full 'price determination' exercise. The Commission does not believe that such an exercise would be justified on a cost-benefit basis, and that it would be more appropriate to take the impact of any change in these taxes into account at the time of the next price review.

Penalties or interest on late payments are factors that are within the distributors' control. As a result, they should be excluded from the definition, in order to provide an incentive for distributors' to reduce such costs.

Fees and charges paid or payable with respect to a distribution licence will be the subject of the separate L-factor adjustment in the price control formula (as described in section 4.3). The L-factor will be determined each year and will therefore directly capture any change in licence fees that occur during the regulatory period. These charges should therefore be excluded from the Relevant Tax definition, and should not trigger a change in taxes event.

In addition to the exclusions outlined above, the Commission considers that the definition of Relevant Tax should make clear that:

- it excludes charges associated with FRC;
- it only includes charges associated with a change in service standards, where the distributor has been directed, ordered or required as a result of legislation or regulatory arrangements to make such a change in service standards; and
- it includes charges associated with the ROLR function.

The Commission's decision in relation to the costs associated with FRC is that such costs should be recovered via the Order in Council process or as part of the revenue requirement for the third access arrangement period (see section 5.1). For clarity, the definition of Relevant Tax should acknowledge that charges in relation to FRC are excluded from the definition.

In relation to changes in costs associated with changes in service levels, the definition of Relevant Tax should make clear that such costs are only to be included as a Relevant Tax when the change in service is as a result of the service provider being directed, ordered or required as a result of legislation or regulatory arrangements to change the service standard provided. The change in tax provisions should not be triggered where the distributor has itself decided to provide a different level of service, since such a decision is under the distributors' control.

Finally, the Commission's position in section 5.1 is that costs associated with the ROLR function should be recovered as a change in taxes event. The definition of Relevant Tax should therefore make clear that charges associated with the ROLR function are included within the definition.

Accordingly, the Commission considers that each of the distributors should revise their definitions of a Relevant Tax to include any royalty, duty, excise, tax, impost, levy, fee or charge (including, but without limitation, any GST) imposed by an Authority in respect of the repair, maintenance, administration or management of the Distribution System (or any part of it) or in respect of the provision of the Reference Services, but excluding:

1. income tax (or State equivalent income tax) and capital gains tax;
2. stamp duty, financial institutions duty, bank accounts debit tax or similar taxes or duties;
3. fees and charges payable for distribution licences or any other membership, contribution or other charge payable to other regulatory bodies in the gas industry;
4. penalties and interest for late payment relating to any tax, royalty, duty, excise, impost, levy, fee or charge;
5. charges associated with changes in service standards, except where the distributor has been directed, ordered or required as a result of legislation or regulatory arrangements to make such a change in service standards;
6. any charge associated with the introduction of Full Retail Competition; and
7. any tax or charge which replaces the taxes and charges referred to in (1) to (6)

For the avoidance of doubt, charges associated with the Retailer of Last Resort function are included within this definition as charges that constitute a relevant tax.

Notification period

Envestra has outlined a number of reasons why it considers that a 12-month notification period is preferable to 3 months. In particular, it is of the view that a 12 month period would allow pass-through applications to be considered concurrently with the annual tariff approval process, would provide more time for distributors to understand any tax change impacts (particularly in relation to tax changes that occur with little public notice) and would allow for the 'bundling' of the impact of multiple tax changes into a single pass-through decision.

The Commission considers that aligning the pass-through and annual tariff approval processes would have little practical benefit from an administrative perspective. The information requirements and the consideration necessary for a pass-through application differ considerably from those relevant for the annual tariff approval process. The latter involves assessing *compliance* with the pre-established price control formulae, whilst the assessment of a change in tax provision requires consideration of the expected economic impact on the business. The Commission notes that there may be potential advantages in aligning the processes from the perspective of customers, to the extent that tariff changes would then occur all at once. However, given that distributors have the ability under the price control arrangements to change tariffs at any point during the year, as well as at the end of each calendar year, the extent of the benefit that this would imply is not clear.

The Commission agrees that a 12 month notification period would provide greater potential for 'bundling' multiple tax changes – to the extent that more than one change in tax event occurred over the course of the notification period. However, again, the Commission does not consider that this would provide a significant benefit from an administrative perspective, since the impact of each change in tax event would still need to be considered on an individual basis. In addition, the Commission notes that the existing arrangements permit the bundling of change in tax events which occur during the three-month notification period, and that the proposed pass-through provisions already provide for the recovery of any previous change in tax event. The latter provision also allows the distributor to revisit the pass-through amounts, if later analysis leads it to conclude that the initial pass-through amount did not adequately reflect the impact of the change in tax event on its business.

As a result, the Commission does not consider the advantages of a 12-month notification period over the existing three month period to be significant.

The Commission noted in the Draft Decision that it considers it desirable to ensure that the processes and timelines applying to each distributor in relation to a change in tax pass-through are consistent. This will ease the administration of the change in tax pass through provisions. A change in tax event can be expected to impact all distributors. Having the same notification requirements for all distributors means that applications for pass-through amounts will be received within a similar timeframe, and can be considered by the Commission largely concurrently. This is likely to lead to administrative efficiencies in determining the appropriate pass-through amount.

In addition, the Commission notes that customers would potentially be disadvantaged if notification periods differed significantly between the distributors. In the event of a negative change in tax pass-through, the Commission cannot initiate a pass-through until the time for notification by the distributor has lapsed. If Envestra's notification period was twelve months, this could mean that Envestra's customers would need to wait a year before the Commission could initiate a negative pass-through amount, whilst the customers of the other distributors could benefit from a negative pass-through after three months.

The Commission is of the view that the above advantages of maintaining a consistent notification period across distributors outweigh any advantages of extending the notification period from the three months proposed by Multinet and TXU.

As a result, the Commission requires Envestra to amend its proposed change in tax pass-through provisions to provide for it to notify the Commission within 3 months of a change in tax pass-through event, rather than 12 months.

The Commission notes that each of the distributors has proposed that the regulator should assess the change in tax pass through applications within a period of 20 business days. This period is consistent with that currently allowed for under the Tariff Order. However, the Commission notes that in the case of electricity distributors, it has 30 business days within which to make a decision on the appropriate pass-through amount.[412]

The Commission considers that the longer 30 business day period provides greater opportunity for it to consult with the distributor (where necessary and appropriate) and to more fully assess any pass-through applications. As a result, the Commission requires each of the distributors to amend their pass-through provisions to provide for the regulator to assess any applications within 30 business days rather than 20 business days.

Ability of the Commission to initiate a change in tax pass-through

In the Draft Decision, the Commission expressed the view that it was important that it (as well as the distributors) had the ability to be able to initiate a change in tax pass-through. In particular, where the change in taxes implied a negative pass-through, distributors may not have an incentive to initiate such a pass-through.

In their responses to the Draft Decision, all distributors pointed out that clause 8.3(a) of their proposed Revisions provides the Commission with the ability to decide on a pass through amount, in the event that the service provider does not apply for a pass-through within the allowed timeframe.

The Commission agrees that the proposed clause 8.3(a) addresses its concern that it should have the ability to initiate a change in tax pass-through event. As a result, the Commission does not require amendments to the proposed Revisions on this matter.

[412] Electricity Distribution Price Determination 2001-2005, Volume II Price Controls, Clause 5.2(iii).

4.8.4 Final Decision

AMENDMENTS REQUIRED

Each of the distributors is required to amend its proposed change in tax pass through provisions (Clause 8) as follows:

Define a 'change in tax event' as:

- **a variation, or withdrawal or introduction of a Relevant Tax, or a change in the way or rate at which a Relevant Tax is calculated, which has a material impact on the costs to the distributor of providing the Reference Services.**

Define a 'relevant tax' as:

- **any royalty, duty, excise, tax, impost, levy, fee or charge (including, but without limitation, any GST) imposed by an Authority in respect of the repair, maintenance, administration or management of the Distribution System (or any part of it) or in respect of the provision of the Reference Services, but excluding:**
  - **(1) income tax (or State equivalent income tax) and capital gains tax;**
  - **(2) stamp duty, financial institutions duty, bank accounts debit tax or similar taxes or duties;**
  - **(3) fees and charges payable for distribution licences or any other membership, contribution or other charge payable to other regulatory bodies in the gas industry;**
  - **(4) penalties and interest for late payment relating to any tax, royalty, duty, excise, impost, levy, fee or charge;**
  - **(5) charges associated with changes in service standards, except where the distributor has been directed, ordered or required as a result of legislation or regulatory arrangements to make such a change in service standards;**
  - **(6) any charge associated with the introduction of Full Retail Competition; and**
  - **(7) any tax or charge which replaces the taxes and charges referred to in (1) to (6)**

For the avoidance of doubt, charges associated with the Retailer of Last Resort function are included within this definition of a relevant tax.

Amend clause 8.2(b) to require the regulator to assess the pass through application within 30 business days.

Envestra is required to amend clause 8.1 of its proposed Revisions for both Victoria and Albury to provide notice of a change in tax event to the Commission within a period of 3 months.

4.9 Establishing the X factors

The link between the price controls described in this chapter and the revenue benchmarks described in sectiona 3.10 for the 2003-07 access arrangement period are the X factors determined for each distributor.

Specifically, the revenue benchmarks derived in the previous chapter are given effect through being translated into a CPI-X regulatory cap on the reference tariffs applying over the 2003-07 access arrangement period. The derivation of the X factor is described below.

In making a price determination in relation to tariffed distribution services for the 2003-07 access arrangement period, the Commission is required to have regard to certain fixed principles that are set out in the Tariff Order. In particular, fixed principle 9.2(b)(2) requires the Commission to set a single X factor without revision for the entire 2003-07 access arrangement period. However, Fixed Principle 9.2(b)(2) also notes that the regulator is not precluded from making a P_0 adjustment to the price path at the start of second regulatory period.[413]

The P_0 and X factors for each distributor have been calculated by setting the net present value (NPV) of the allowed reference tariff revenue over the period 2003-07 equal to the NPV of the forecast revenue requirement, for each distributor.

The forecast revenue requirement has been determined by the building block approach as outlined in chapter 3.

In estimating future reference tariff revenue, the Commission has used forecast quantities for each of the years 2003-07, for each of the distributors' tariff components, and multiplied these quantities by an assumed price for each tariff component.

In addition to the above assumptions, the Commission notes that each P_0 and X factor has also been rounded down to one decimal place.

4.9.1 Final Decision

Consistent with the above discussion, the Commission has derived two X factors for each distributor as part of this Final Decision:

- an initial P_0, which represents the limit on the weighted average price changes for prescribed distribution services in 2003 (the first year of the 2003-07 access arrangement period); and
- a further X, which represents the limit on the weighted average price changes in each of the years 2004 through to 2007.

The X factors to apply in each year of the following regulatory period are outlined in table 4.2.

413 P_0 is the term used to refer to the X factor adjustment in the first year of a given regulatory period, which reflects the change in prices from the last year of the previous regulatory period to the first year of the new regulatory period.

TABLE 4.2

FINAL DECISION: REFERENCE TARIFF X FACTORS TO APPLY TO EACH DISTRIBUTOR, 2003-07

	Draft Decision		Final Decision	
	2003	2004-07	2003	2004-07
Envestra Albury	5.8%	1.0%	2.6%	1.0%
Envestra Victoria	10.9%	1.0%	9.9%	1.0%
Multinet	6.8%	1.0%	2.0%	-0.7%
TXU	1.4%	1.0%	2.0%	-0.5%

Setting X factors as set out above is mathematically equivalent to, and amounts to, applying a CPI-X escalation to an average price basket as contemplated by the Tariff Order's fixed principle 9(b)(1)(A).

AMENDMENTS REQUIRED

Each of the distributors is required to amend its proposed Revisions to provide for X_t to be defined as follows:

- **For Envestra (Albury), Xt is 0.026 for calendar year 2003 and 0.01 for each of the calendar years 2004-07;**
- **For Envestra (Victoria), Xt is 0.099 for calendar year 2003 and 0.01 for each of the calendar years 2004-07;**
- **For Multinet, Xt is 0.020 for calendar year 2003 and –0.007 for each of the calendar years 2004-07; and**
- **For TXU, Xt is 0.020 for calendar year 2003 and –0.005 for each of the calendar years 2004-07**

5 MISCELLANEOUS ISSUES

5.1 Fixed principles

Under section 8.47 of the Gas Code, a reference tariff policy may provide for principles that are fixed for a specified period of time. Once fixed, these principles have the effect of restricting the regulator's discretion at future reviews in relation to those specified matters. Accordingly, fixed principles provide the regulator with the capacity to make a legally binding commitment on particular matters at future reviews as well as provide distributors and users with greater certainty about the approach to be taken in future reviews.

Such a binding commitment may be particularly useful where consistency in approach is required over time to avoid creating windfall gains or losses, as well as where the ability to pre-commit to certain principles may strengthen the incentives on the distributors to pursue efficiency gains.

Section 8.48 of the Gas Code requires the Commission to consider 'the interests of the service provider and the interests of users and prospective users'. The same considerations apply to determining the fixed period to apply to each fixed principle. As the principles form part of the distributors' reference tariff policies, the Commission is required to ensure that the principles comply with the objectives set out in section 8.1 of the Gas Code.[414]

Each of the distributors' existing Access Arrangements already include certain fixed principles that the Commission is required to comply with when deciding whether to approve or not approve the distributors' proposed Revisions. These fixed principles are set out in the Tariff Order and are to apply in making a price determination for the 2003-07 access arrangement period.

In addition, each of the distributors has proposed fixed principles that they intend to bind both the Commission and themselves in the process of assessing future Revisions to their Access Arrangements (ie. beyond 1 January 2003). Broadly, the proposed fixed principles relate to the following:

- the regulatory approach to be adopted in future access arrangement periods;
- the adoption of a single X-factor without revision in future access arrangement periods;
- consistency between the tariff control formula adopted in the third access arrangement period and that adopted in the second access arrangement period;
- a description of the efficiency carryover arrangements to apply in the third access arrangement period, including the approach to carrying over positive and negative carryover amounts;
- use of the capital asset pricing model (CAPM) to determine the rate of return in future regulatory periods;

414 Gas Code, sections 2.46, 3.5 and 8.1.

- specification of the nature of adjustments that are to be made to the capital base;
- recovery of ongoing costs associated with implementing FRC and implementing the retailer of last resort obligations; and
- providing scope to delete any of the fixed principles where there is a change in the Gas Code.

5.1.1 Regulatory approach to be adopted in future regulatory periods

Each of the distributors has proposed a general fixed principle in their respective reference tariff policies that specifies the broad regulatory approach that will be taken in future access arrangement periods.

Specifically, the relevant provisions proposed by the distributors require that, in approving revisions to the proposed Access Arrangements:

> The regulator will use incentive based regulation adopting a CPI-X approach and not rate of return regulation. This fixed principle will apply for a period of 30 years from the commencement of the second access arrangement period.[415]
>
> The regulator will not utilise rate of return regulation. This fixed principle will apply until the end of the third access arrangement period.[416]
>
> [The regulator is to utilise] incentive based regulation adopting a CPI-X approach and not rate of return regulation. This fixed principle will apply until the end of the third access arrangement period.[417]

The Commission notes that there are differences in the nature of the wording of each of distributors' proposed fixed principles and in relation to the period over which the principle is to be fixed.

In the Access Arrangement Information accompanying its proposed Revisions, Envestra argued that this proposed fixed principle reflects the fact that it generally supports the use of CPI-X incentive-based regulation as the best way of ensuring that distribution services are delivered at efficient costs, and considered that this principle should be enshrined as a fixed principle. It also noted that such a fixed principle was consistent with fixed principle 9.2(b)(1) in the existing Tariff Order.[418]

415 Envestra, clause 7.1(e)(1).
416 Multinet, clause 7.2(a)(1).
417 TXU, clause 7.2(a)(1).
418 Envestra, Access Arrangement Information, 2 April 2002, p.50.

Envestra did not set out in its earlier submission why it sought to lock-in the fixed principle for 30 years from the commencement of the second access arrangement period. In response to a request for further clarification from the Commission, Envestra stated its view that it is important for the fixed principle to be enshrined in order to provide a reasonable level of certainty regarding the method of calculation of the rate of return in future periods, given that Envestra invests in assets which will last for more than 50 years.[419] Enshrining the fixed principle for 30 years addresses the regulatory risk that Envestra would otherwise face if the method used to calculate the rate of return changed in future. This in turn means that the regulatory risk component of the WACC can be reduced, with the result that long-term tariffs to users are minimised. Envestra considers 30 years is the minimum time span over which a financial return for a distribution network should be modelled.

Multinet indicated that its proposed fixed principle reflects an amendment to an existing fixed principle in the Tariff Order and provides certainty by ensuring that rate of return regulation is not used as a form of price regulation for the following access period.[420]

TXU did not discuss the reasons for this proposed fixed principle in its Access Arrangement Information.

The Commission notes that the incentives embodied within the regulatory regime will be strengthened to the extent that the distributors anticipate that the key features of the regime will continue to be applied going forward. A commitment to apply incentive regulation as embodied in the CPI-X approach is consistent both with the Commission's current practice. As such, the Commission considers that it is appropriate to include a fixed principle in the distributors' Access Arrangements that allows for an ongoing commitment to a CPI-X approach to incentive regulation, rather than rate of return regulation.

Given that regulatory approaches need not fall into only two camps (ie. being *either* rate of return *or* incentive regulation), the Commission considers it appropriate to require Multinet to amend its proposed fixed principle to include a reference to the regulatory approach that will be adopted (rather than only to the approach which will not be adopted), namely 'incentive based regulation adopting a CPI-X approach'.

In relation to the proposed fixed period, the Commission notes that Envestra is the only one of the three distributors to propose a 30-year fixed period. As noted above, the Commission recognises that the incentives provided to distributors will be enhanced where there is a greater commitment by the regulator to maintain the arrangements giving rise to those incentives. However, the underlying legislative arrangements also recognise the importance of the regulator maintaining discretion to be able to deal with unforeseen events and changes in circumstances.

---

419 Email from A. Staniford (Envestra) to N. Southern (ESC), 9 September 2002.

420 Multinet, Access Arrangement Information, 28 March 2002, p.66. At the time of finalising this report, Multinet had not responded to the Commission's further request for information clarifying why it had not incorporated a reference to CPI-X within its proposed fixed principle.

The Commission does not consider that the incentives provided to distributors would be *materially* strengthened by fixing the same approach for 30 years. The latter itself provides a rationale for the regulator to maintain its approach, unless circumstances give rise to good reasons for change. As a result, the Commission requires Envestra to amend its proposed fixed principle to apply until the end of the third access arrangement period, rather than for 30-years.

AMENDMENTS REQUIRED

Multinet is required to amend its proposed fixed principle 7.2(a)(1) to refer to the regulator utilising incentive based regulation adopting a CPI-X approach as the form of regulation to apply until the end of the third access arrangement period.

Envestra is required to amend its proposed fixed principle 7.1(e)(1) (for both Victoria and Albury) so that it applies until the end of the third access arrangement period rather than 30 years.

5.1.2 Adopting a single X factor without revision

Both TXU and Multinet have proposed a fixed principle that requires the regulator to apply a single X factor for the entire third access arrangement period, where it uses a CPI-X approach to regulation. Both distributors have proposed that the fixed principle should apply until the end of the third access arrangement period.

Specifically, the wording of the proposed fixed principles included in their respective reference tariff policies is as follows:

> [The regulator is to adopt] an X factor in the CPI-X formula so that only one X factor applies without revision for the entire third access arrangement period to which the decision applies. This fixed principle will apply until the end of the third access arrangement period.[421]
>
> If the regulatory approach is incentive-based regulation adopting a CPI-X approach, then the regulator will adopt an X factor in the CPI-X formula so that only one X factor applies without revision for the entire third access arrangement period to which the decision applies.[422]

In its Access Arrangement Information, Multinet indicated that this proposed fixed principle reflected an existing fixed principle in the Tariff Order. Further, it indicated that, to the extent that CPI-X approach to incentive base regulation applied, the effect of the principle is to apply any price variation evenly throughout years two to five of the access arrangement period.[423] In response to the Draft Decision, Multinet noted that the approach adopted by the Commission in its Draft Decision was consistent with the intent of this proposed fixed principle.[424]

421 TXU, clause 7.2(a)(2).
422 Multinet, clause 7.2(a)(1).
423 Multinet, Access Arrangement Information, 28 March 2002, p.66.
424 Multinet, Response to the Draft Decision, p.101.

TXU's Access Arrangement Information did not discuss the justification for the proposed fixed principle. In response to the Commission's request for further clarification, TXU noted that the purpose behind the fixed principle is to provide customers and the distributors with some certainty beyond the current regulatory period regarding the form of the price control. The intent is that following the reset via the P_0 adjustment, the next four annual price adjustments would be applied in a consistent manner across all tariffs and customer classes and that the rate of adjustment (the X factor) would not vary from year to year.[425]

The Commission notes that the current fixed principle in the Tariff Order that requires the setting of a single X-factor also contains the proviso that:

> … (for the avoidance of doubt), this clause does not preclude the regulator from making P_0 adjustments (whether partial or otherwise) to the price path at the start of the subsequent access arrangement period.[426]

This fixed principle applies only in relation to the Commission's current review of the Access Arrangements that will apply for the 2003-07 period.

The information subsequently provided by TXU further clarifies that it does not intend to preclude the use of P_0 adjustments in future regulatory periods. Similarly, Multinet's response to the Draft Decision implies that it also does not intend to preclude the use of P_0 adjustments in future regulatory periods, given that the Commission's Draft Decision adopted a combination of a P_0 adjustment with a smoothed price path (ie. a single X factor) thereafter.[427] To ensure transparency, the Commission considers that it is appropriate for both Multinet and TXU to amend their proposed fixed principle to clarify that it does not preclude P_0 adjustments.

The Commission notes that the wording of Multinet's proposed fixed principle leaves open the specific approach to incentive regulation that is adopted by the regulator.

Consistent with the Commission's decision above, Multinet is required to amend its proposed fixed principle 7.2(a)(2) to clarify that the regulatory approach to be adopted until the end of the third access arrangement period will be incentive-based regulation adopting a CPI-X approach.

AMENDMENTS REQUIRED

Multinet and TXU are each required to amend their proposed fixed principle 7.2(a)(2) to clarify that the requirement to adopt a single X factor does not preclude a P_0 adjustment in future access arrangement periods.

Multinet is required to amend its proposed fixed principle 7.2(a)(2) to clarify that the regulatory approach will be incentive-based regulation adopting a CPI-X approach.

---

425 Email from B. Frewin (TXU Networks) to N. Southern (ESC), 10 September 2002.

426 Tariff Order, clause 9.2(b)(2).

427 Multinet did not respond to the Commission's request for clarification on this matter.

5.1.3 Consistent tariff control formula in the second and third access arrangement periods

TXU has proposed an additional fixed principle, which specifies that:

> The tariff control formula by which tariffs for haulage reference services vary during the third access arrangement period shall be consistent with the tariff control formula contained in clause 3.[428]

TXU's Access Arrangement Information did not outline the justification for the proposed fixed principle. In response to a request for clarification from the Commission, TXU noted that the purpose of this fixed principle is to provide both customers and the distributors with some certainty about the regulatory approach following the end of the second access arrangement period. TXU notes that, as the proposals for price controls for the second period were different from those applying in the first regulatory period, its proposed fixed principle will require that the new controls be in place for a minimum of two access arrangement periods.[429]

TXU's proposed fixed principle would effectively prevent any revisions to the price control formula in the third access arrangement period. The Commission considers that such a fixed principle would be inappropriate, given that there may be changes in circumstances that may be best addressed through changes to the formulation of the price control.

For example, the Commission has introduced an L-factor in the price control formula for the second access arrangement period to address the issue of licence fee cost variability, which would make it problematic to include those costs directly within the revenue requirement. It is possible that in the third access arrangement period other cost categories may emerge as being subject to significant external variation, and would be best incorporated into the regulatory regime via the price control formula.

In addition, the Commission has noted in this Final Decision that it does not intend to introduce a service incentive mechanism within the price control for this access arrangement period. However, it has previously expressed the view that it will review the need for an S-factor adjustment to the price controls for the 2003-07 access arrangement period in light of more comprehensive information to be collected on reliability performance over the forthcoming access arrangement period.[430]

As a result, the Commission does not consider that TXU's proposed fixed principle is in the interests of distributors nor users and prospective users, and requires that fixed principle to be deleted from TXU's proposed Revisions.

AMENDMENTS REQUIRED

TXU is required to delete its proposed fixed principle 7.2(a)(3).

428 TXU, clause 7.2(a)(3).

429 Email from B. Frewin (TXU Networks) to N. Southern (ESC), 10 September 2002.

430 Office of the Regulator-General, Position Paper, 2003 Review of Gas Access Arrangements, September 2001, p.12.

5.1.4 Treatment of a positive efficiency carryover

Each of the distributors has proposed a fixed principle in relation to the carrying over of any positive efficiency gains from the second access arrangement period to the third. Specifically, the wording proposed by each distributor for this fixed principle is:

> To the extent that the application of clause 6.4 results in a positive efficiency carryover at the end of the Second Access Arrangement Period, the reward earned in the Second Access Arrangement Period is to be added to the Total Revenue and carried forward into the Third Access Arrangement Period, until it has been retained by the Service Provider for a period of five full years. This fixed principle will apply until the end of the Third Access Arrangement Period, in accordance with clause 6.4.[431]

> An efficiency carryover that is achieved in Calendar Year t of an Access Arrangement Period will be added to each year of the Total Revenue requirement in future Access Arrangement Periods until it has been retained by the Service Provider for a total period of 10 years. This fixed principle will apply to efficiency gains (or losses) incurred in the First and Second Access Arrangement Periods.[432]

Multinet noted in its response to the Draft Decision that the Commission did not appear to require any amendment to its proposed fixed principle, and stated that it has interpreted this to mean that the Commission has accepted this principle.[433]

The Commission interprets this proposed fixed principle as requiring the calculation of any positive efficiency carryover amount applying in the second access arrangement period to be included in the revenue requirement calculated for the third access arrangement period. The Commission confirms that it accepts Multinet and TXU's proposed fixed principle.

However, in relation to Envestra's proposed fixed principle, the Commission notes that it has discussed elsewhere in this Final Decision that it considers a five year period for the carryover of efficiency gains to be appropriate, rather than the ten year period proposed by Envestra. The Commission considers the primary purpose of the efficiency carryover mechanism to be the 'smoothing' of the incentive to make gains throughout the access arrangement period, and notes that a five-year carryover period adequately achieves this. The Commission's consideration of Envestra's proposal is discussed fully in section 3.8. As a result, Envestra is required to amend its fixed principle to allow the carryover of efficiency gains for a total of five (rather than ten) years.

AMENDMENTS REQUIRED

Envestra is required to amend clause B7.2(a) and B7.2(c)(1) of its proposed Revisions (for both Victoria and Albury) to allow the carryover of efficiency gains (or losses) for a total of five (rather than ten) years.

431 TXU, clause 7.2(9); Multinet, clause 7.2(8).
432 Envestra, clause 7.2(c)(1).
433 Multinet, Response to Draft Decision, p.106.

5.1.5 Treatment of a negative efficiency carryover

Each of the distributors has proposed a fixed principle that prohibits the carryover of any negative efficiency amount from the second to the third access arrangement period.

Specifically, the wording proposed by each distributor for this fixed principle is:

> To the extent that the application of clause 6.4 results in a net negative efficiency carryover at the end of the Second Access Arrangement Period, there is to be: (A) no consequential adjustment to Total Revenue for the purpose of determining Reference Tariffs for the Third Access Arrangement Period; and (B) no carryover into the Third Access Arrangement Period by any other means. This fixed principle will apply until the end of the Third Access Arrangement Period.[434]
>
> There will be no negative carryovers from one Access Arrangement Period to the next.[435]

The treatment of negative carryovers arising under the efficiency carryover mechanism is discussed in detail in section 3.8.5 of this Final Decision.

In relation to the carryover of negative efficiency gains from the second to the third access arrangement period, the Commission notes that it requires amendments to the proposed fixed principle to reflect the Commission's conclusion that it needs to retain discretion in determining the treatment of any negative carryover amount, so that the incentive for distributors to make efficiency gains in the last year of the access arrangement period, in the face of an accrued negative carryover amount, are not distorted.

The Commission also requires revisions to the proposed fixed principle to set a floor of zero on the efficiency carryover amount applied in any one year, and for any negative amount to be accrued between years on the basis of the pre-tax WACC. This provision ensures that there is clarity in determining what constitutes 'a negative efficiency carryover'.

434 TXU, clause 7.(a)(10); Multinet, clause 7.2(a)(9).

435 Envestra, clause 7.2(c)(3).

AMENDMENTS REQUIRED

Multinet and TXU are each required to amend their proposed fixed principles to:

- **clarify that a negative carryover amount from the second access arrangement period is calculated as the net present value of the carryover amount calculated for individual years, at the pre-tax WACC applying for the third access arrangement period**
- **permit the Commission to exercise its discretion in choosing whether to apply any negative amounts from one access arrangement period to the next [Multinet clause B7.2(a)(9); TXU B7.2(a)(10)].**

Envestra is required to amend its proposed Revisions (for both Victoria and Albury) to:

- **clarify in clause B7.2(c)(2) that, in carrying over an accrued negative amount from one year to the next, the negative amount will be multiplied by the pre-tax WACC applying to Envestra for the third access arrangement period;**
- **reinstate its earlier proposed clauses 7.2(c)(3) and (4), to permit the Commission to exercise its discretion in choosing whether to apply any negative amounts from the one access arrangement period to the next.**

5.1.6 Efficiency carryover mechanism

In addition to the proposed fixed principles outlined above relating to the treatment of positive and negative efficiency carryovers, the Commission notes that Envestra has proposed a fixed principle describing how the efficiency carryover arrangements will operate in calculating the efficiency carryover amount to be carried over from the second to the third access arrangement period. In contrast, Multinet and TXU have both described the same efficiency carryover arrangements in their respective reference tariff policies, but not sought to include the mechanics of the arrangements as fixed principles.

Whilst the Commission does not consider it necessary to include the description of the efficiency carryover arrangements in the form of a fixed principle, it does not object to Envestra doing so, particularly if it believes that it will provide it with greater certainty about the incentive arrangements to apply in the following access arrangement period.

However, in order for Envestra's proposed fixed principle to be approved, the Commission considers that it should be amended to reflect the proposed efficiency carryover mechanism arrangements as discussed in section 3.8 of this Final Decision. As a result, the Commission requires Envestra to amend its proposed fixed principle contained in clause B7.2(b)(6) to give effect to the following.

While the Commission considers it is appropriate to provide some certainty with respect to the calculation of the efficiency carry over, as discussed in sections 2.4 and 3.4, it does not consider it appropriate to provide a carry over of ‘gains’ that have come at the expense of declining service levels, or from a failure to undertake the scope of renewal works that have been assumed in this Final Decision. As there may well be legitimate reasons for changes in the scope of works performed in a five-year period from that expected at the start of the regulatory period, this inevitably would require the Commission exercise discretion as to whether or not it is appropriate for some or all of the gains to be excluded from the carry over. Accordingly, the Commission requires the distributors’ fixed principles on the efficiency carry over to be amended to permit the Commission to isolate gains that have come at the expense of a decline in service levels or a deferral of renewal works.

AMENDMENTS REQUIRED

Envestra is required to amend its proposed Revisions for both Victoria and Albury to:

- **in clause B7.2(b)(6)(A), clarify that the operating expenditure benchmark for the first year of the next access arrangement period will be set with regard to actual operating expenditure in the penultimate period of the previous access arrangement period and the assumed efficiency gain between the penultimate and final periods embodied in the operating expenditure benchmarks.**
- **in clause B7.2(b)(6)(B), clarify that at the regulatory review for the fourth access arrangement period there will be an adjustment to the regulatory asset base to take account of the difference between forecast and actual capital expenditure in the last year of the second access arrangement period.**
- **add a clause describing the mechanism for adjusting the expenditure benchmarks in the second access arrangement period to take account of growth in calculating the efficiency carryover amount for the third access arrangement period. This should also specify the fixed expenditure amounts per connection and the benchmark connection numbers set out in this report;**
- **add a clause describing the mechanism for adjusting the expenditure benchmarks for the second access arrangement period to take account of changes in scope in calculating the efficiency carryover amount for the third access arrangement period; and**
- **add a clause clarifying that the efficiency carryover amount will be calculated as the net amount of the efficiency gains (or losses) relating to capital and non-capital expenditure.**

Each of the distributors is required to amend their efficiency carryover fixed principles to clarify that the formula for calculating the efficiency carryover is subject to the Commission being satisfied that the service levels and scope of renewal works expected at the start of the access arrangement period have been delivered.

5.1.7 Use of the Capital Asset Pricing Model

Each of the distributors proposed a fixed principle in relation to the methodology adopted to derive the return assumed in determining reference tariffs. Specifically, the relevant fixed principle proposed was:

> To the extent that the Rate of Return is relevant to the determination of Reference Tariffs, the Rate of Return on the Capital Base shall be calculated using the Capital Asset Pricing Model and shall be applied to the Capital Base on a real, post-tax basis.[436]

[436] TXU, clause 7.29a)(7); Multinet, clause 7.2(a)(6).

> In the event that the Regulator applies a post-tax formulation of the CAPM to the Capital base in the Second Access Arrangement Period, then the same post-tax approach will be applied to the Capital Base in the Third Access Arrangement Period and subsequent Access Arrangement Periods.[437]

Essentially, this would require the Commission at future reviews to:

- adopt the capital asset pricing model (CAPM) to estimate the costs of capital associated with the distributors' regulated activities; and
- adopt an after-tax version of the WACC (which is interpreted as meaning that an explicit allowance should continue to be made for company taxation, rather than transforming an after-tax WACC into a pre-tax WACC).

These principles were proposed to remain in effect for 30 years after their approval.

The Gas Code states that the return to investors assumed in the assessment of reference tariffs should reflect an unbiased estimate of the cost of capital associated with the regulated activities. In the Draft Decision, the Commission noted that, while it has accepted the CAPM as the most appropriate method of estimating costs of capital at that point in time, and has used it in every decision to date, it was concerned that locking in a particular methodology may preclude adopting a superior model in future if one emerges. It noted that the CAPM is subject to ongoing criticism, and new models are being developed continually.[438] It also noted that the rate of increase in capital market information relevant to regulated utilities may permit other existing models for estimating costs of capital to be applied at future reviews – probably in addition to the CAPM, but possibly as an alternative.[439] Further, approving a principle that would preclude a more robust methodology for estimating the cost of capital may lead to the objectives in section 8.1 of the Gas Code not being met, and might not be in the either interests of users and prospective users nor the interests of distributors.

Finally, the Commission expressed the view that the distributors' proposal to lock in the use of the CAPM for 30 years is not completely consistent with their comments elsewhere on the CAPM. In particular, the distributors commented that the CAPM should be 'just one input into defining the appropriate cost of capital',[440] and that it is 'a theoretical model that does not fully explain security returns'.[441] It is not clear whether the requirement to apply the CAPM at future reviews would not preclude other 'inputs' or 'explanations of security' returns to be taken into account.

Accordingly, in the Draft Decision the Commission required the distributors to delete the fixed principles locking in the use of the CAPM for 30 years.

---

437 Envestra, clause 7.1(e)(5).

438 The Commission noted that the CAPM itself is only a little over 30 years old.

439 It was noted that, in the US – where there is a substantial amount of capital market information available – variants of the dividend growth model, rather than the CAPM, are the dominant models used for estimating the cost of capital in regulatory proceedings.

440 Envestra, Access Arrangement Information, p.A12.

441 Multinet, Access Arrangement Information, schedule 1, p.1.

In contrast, the Commission noted that it saw merit in approving a fixed principle that locks in an after-tax WACC (and explicit allowance for tax) at future reviews, given the approach adopted in the Draft Decision. The Commission has previously commented that a number of factors may lead to the benchmark rate of company tax paid (as a proportion of regulatory profit) changing over time. It has noted that this implies that a change from an after-tax WACC to a pre-tax WACC where the allowance for taxation is based upon a long-term average rate of company tax (as implied a pre-tax WACC derived using a simple transformation) would have the potential to create windfall gains or losses. Accordingly, the Commission accepted this part of the proposed fixed principle.

In its response to the Draft Decision, Multinet proposed to revise its fixed principle to provide for it to be locked in just for the third access arrangement period:

> While it could be argued that the Access Code provides for the Regulator with the agreement of Service Providers to amend the Fixed Principle, should such an alternative approach be identified, Multinet accepts the thrust of the Regulator's position. However, Multinet does believe that it is appropriate for there to be some certainty going forward and proposes that the CAPM apply at least for the next review period.[442]

Multinet proposed revised drafting to its fixed principle that would give effect to this intention, as follows:

> a) To the extent that the Rate of Return is relevant to the determination of Reference Tariffs, the Rate of Return on the Capital Base shall be calculated on a real, post-tax basis.
>
> If applicable, this Fixed Principle applies for 30 years.
>
> To the extent that the Rate of Return is relevant to the determination of Reference Tariffs, the Rate of Return on the Capital Base shall be calculated using the Capital Asset Pricing Model.
>
> This Fixed Principle will apply until the end of the third access arrangement period.[443]

Envestra accepted the Commission's proposed required amendment:

> While Envestra believes this eventuality can be dealt with by the two parties agreeing to terminate the Fixed Principle (which the Code permits to occur at any time) it nevertheless accedes to the Commission's request.[444]

It also submitted proposed drafting to implement this intention, as follows:

> In the event that the Regulator applies a post-tax return to the Capital Base in the Second Access Arrangement Period, then the same post-tax approach (including the method for determining tax depreciation) will be applied to the Capital Base in the Third Access Arrangement Period and subsequent Access Arrangement Periods. This Fixed Principle will apply for a period of 30 years.

---

442 Multinet, Response to Draft Decision, p.105.
443 Multinet, Response to Draft Decision, p.105.
444 Envestra, Response to Draft Decision, p.11.

TXU, on the other hand, sought to clarify the required amendment:

> TXU Networks request that the Commission consider an amendment to this fixed principle to provide greater clarity. The amended fixed principle would seek to have the effect that, in the event that the Regulator applies a post tax formulation of the CAPM return to the Capital Base in the second period, then the same post tax approach, including the method for determining tax depreciation, will be applied in the third and subsequent periods.[445]

The distributors also commented that they considered the Commission's reluctance to permit the CAPM to be locked-in for 30 years to add to 'regulatory risk'. TXU and Multinet commented as follows:

> TXU Networks note, however, that the Commission will not commit to applying the CAPM to assessing the cost of capital in future reviews. Rather it states that it "*has only accepted the use of the CAPM as the most appropriate model <u>at this point in time</u>*. (emphasis in original)
>
> The Commission's position adds further regulatory uncertainty. It also sits rather uncomfortably with the Commission's apparent confidence that it has been conservative in this decision. This is because the Commission's lack of commitment to the CAPM implies a lack of confidence that the model will stand the test of time. This appears to draw into question the basis of the decisions made using the CAPM.[446]

The Commission considers that not mandating the use of the CAPM for another 30 years would not add substantially to regulatory uncertainty, as suggested by the distributors, but remains of the view that such a principle would unduly restrict to adoption in improvements in finance theory and practice. The Commission also remains of the view that the distributors' concern to lock in the use of the CAPM stands at odds with the reservations they have expressed elsewhere about its use. However, it notes that Multinet has proposed an alternative principle to lock-in the use of the CAPM for the 2007 regulatory review. The Commission does not consider that this latter proposal unduly restricts the flexibility available to adopt developments in finance theory and practice, and so reduce the likelihood that the continued use of the CAPM may be inconsistent with the objectives in section 8.1. Accordingly, the Commission accepts Multinet's proposed revision, and considers it appropriate to offer TXU and Envestra the alternative of either removing the reference to the CAPM (as required in the Draft Decision) or adopting the compromise proposal of Multinet.

---

445 TXU, Response to Draft Decision, p.17.

446 TXU, Response to the Draft Decision, p.13; Multinet, Response to the Draft Decision, p.13.

AMENDMENT REQUIRED

Multinet is required to give effect to its foreshadowed amendment to its proposed fixed principle that provides for the use of the CAPM to be locked in for the third access arrangement period only.

TXU and Multinet are required either to:

- **delete the proposed fixed principle requiring the continued use of the capital asset pricing model (CAPM) for 30 years; or**
- **revise the fixed principle to provide for the use of the CAPM to be locked in for the third access arrangement period only.**

5.1.8 Adjustments to the capital base

All of the distributors proposed a fixed principle guiding the calculation of the capital base at future reviews. The principle proposed by TXU and Multinet was:

> To the extent that the Capital Base is relevant to the determination of Reference Tariffs, the value of the Capital Base at the start of the Second Access Arrangement Period, will be adjusted to take account of:
>
> (A) Changes to CPI over the Second Access Arrangement Period;
>
> (B) Depreciation;
>
> (C) New Facilities Investment meeting the requirements of section 8 of the Access Code;
>
> (D) Disposals in the ordinary course of business since 1 January 2003, other than a disposal of:
>
> (i) all of the assets and liabilities of the Service Provider;
>
> (ii) assets pursuant to which the assets of the Service Provider are sold and leased back to the Service Provider; and
>
> (E) the Capital Base will not be reduced as a result of assets forming part of the Capital Base becoming redundant.[447]

Envestra substituted clause D for:

> (D) The value on the Capital Base of assets that are disposed of in the ordinary course of business since 1 January 2003, other than a disposal of:
>
> (i) all of the assets and liabilities of the Service Provider;
>
> (ii) assets pursuant to which the assets of the Service Provider are sold and leased back to the Service Provider;[448]

447 Multinet, clause 7.2(a)(3), TXU, clause 7.2(a)(4).
448 Envestra, clause 7.1(e)(2).

These principles were proposed to apply at the next review (in the cases of TXU and Multinet) and for 30 years from 1 January 2003 (in the case of Envestra).[449]

The principles in clauses A-C are not contentious, and are accepted. Clauses D and E give effect to policy issues discussed elsewhere, being:

- the Commission's ability to remove 'redundant capital' from the distributors' capital bases at the next (or subsequent) reviews; and
- how the capital base should be adjusted for disposals at subsequent reviews.

These are discussed in turn below. In addition, Multinet has proposed a change to its fixed principles to govern whether an adjustment should be made to the capital base at the next regulatory review for differences between actual and forecast capital expenditure in the last year of the current period (ie. 2002). This is also discussed below.

Redundant capital (Clause E)

Each of the distributors proposed a fixed principle that would preclude the removal of redundant capital for the years from 1 January 2003 (in the case of Envestra) and at the next review (in the cases of TXU and Multinet).[450]

As discussed in section 3.7, the Commission accepted the distributors' proposed fixed principles in the Draft Decision. This implied that, while the fixed principle would apply at the next price review for TXU and Multinet, it would apply for 30 years for Envestra.

Since the Draft Decision, Multinet proposed aligning the period for this fixed principle to that approved for Envestra:[451]

> Multinet concurs that there is potential benefit to consumers and Service Providers in this principle applying for a longer period than the 5 years it initially proposed and therefore proposes to align the period of application with that set in Envestra's Access Arrangement Period.

As noted in section 3.7, the Commission will accept this proposed amendment from Multinet. While TXU did not comment expressly on this matter, the Commission invites it also to align the fixed period applicable to this fixed principle to that accepted for Envestra.

449 Envestra, Access Arrangement, clause 7.1(e); Multinet, Access Arrangement, clause 7.2 (a); TXU, Access Arrangement, clause 7.2 (a).
450 Envestra, Access Arrangement, clause 7.1(e); Multinet, Access Arrangement, clause 7.2 (a); TXU, Access Arrangement, clause 7.2 (a).
451 Multinet, Response to Draft Decision, p.102.

Disposals (Clause D)

As discussed in section 3.5, the Commission proposed in the Draft Decision that the distributors' capital bases be adjusted for the proceeds of disposals (rather than their regulatory book value). The implementation of this approach would require a change to clause D of Envestra's proposed fixed principle.[452]

In its submission on the Draft Decision, Envestra accepted the Commission's required amendment, and proposed the following revised clause D:

> The sale value of assets that are disposed of in the ordinary course of business since 1 January 2003, other than a disposal of: all or part of the Distribution System, in which case the value in the Capital Base shall apply; or assets pursuant to which the assets of the Service Provider are sold and leased back to the Service Provider.[453]

The Commission accepts the proposed amendment.

Adjustment for 2002 capital expenditure

As discussed in section 3.8, information on the expenditure for the last year of the access arrangement period will not be available at the time at which a decision is made, and so an assumption about this expenditure is required. For capital expenditure, the Commission has included the original forecast of capital expenditure for 2002 in the capital base for both Multinet and Envestra (adjusted for growth), and has foreshadowed repeating this approach at the next price review (the reasons for which are set out in section 3.8. An updated forecast has been used for TXU for this period to reflect its specific circumstances.

In explaining its proposal, the Commission has noted that it would update the assumed expenditure in the last year of any access arrangement period for the actual value at the subsequent regulatory re-set. This implies that an adjustment in respect of 2002 will be made when assessing reference tariffs for the period from 2008. In its response to the Commission's proposal in the Draft Decision, Multinet proposed requiring that the adjustment foreshadowed by the Commission be given effect in its fixed principles:

> Multinet proposes to amend Fixed Principle 3 to include a sub-clause which requires that the Capital Base in the first year of the Third Access Arrangement (2008) be adjusted to include the difference between the benchmark capital expenditure and the actual capital expenditure incurred in the final year of the First Access Arrangement Period (2002).
>
> Multinet does not expect the proposed new sub-clause in Fixed Principle 3 to be contentious as it seeks no more than to enshrine the Regulator's stated position.

452 The relevant clause for TXU and Multinet is not inconsistent with treating disposals in this manner at future reviews.

453 Envestra, Response to Draft Decision, p.37.

> Approval of the Fixed Principle is important, however as it provides Multinet with certainty that the Regulator's preferred position will be implemented in due course.[454]

The Commission agrees with Multinet that it is appropriate for the fixed principles to require the adjustment for the difference between assumed and actual capital expenditure in 2002 when the capital base is updated for the next price review, and so will accept such a revision to its fixed principle. The Commission also invites TXU and Envestra also to adopt an amendment to their fixed principles to this effect.

5.1.9 FRC cost recovery

Each of the distributors has submitted two fixed principles that would require certain of the costs associated with implementing FRC to be reflected in reference tariffs in the third access arrangement period. Broadly, these principles defined two sets of costs, which were capital and operating costs that had either:

- Principle 1: been approved under the FRC Order in Council (OIC) process, but not fully recovered by the end of the second access arrangement period through prices, charges or fees set under the OIC; or
- Principle 2: not been approved (and therefore not recovered) through the FRC Order in Council process, and not recovered through reference tariffs in the second access arrangement period.

In the Draft Decision, the Commission expressed its view that the FRC Order in Council already appeared to provide a framework for the recovery of the incremental costs associated with implementing FRC, including costs incurred during the 2003-07 access arrangement period. Further, the expenditure forecasts used in the assessment of reference tariffs incorporated an allowance for certain activities such as billing and revenue collection, which are expected to increase as a consequence of FRC (but are not recoverable through charges set pursuant to the OIC). As a result, the Commission did not consider that these fixed principles were required.

The comments received in response to these two fixed principles are discussed in further detail separately below, together with the Commission's further analysis and conclusions.

Principle 1: Recovery of previously approved Order in Council costs

DISTRIBUTORS' PROPOSALS

The distributors have each proposed a fixed principle that requires:

- any outstanding capital costs at the end of Calendar Year 2007 approved under the OIC to be included in the capital base to be used to calculate reference tariffs for the third access arrangement period; and

454 Multinet, Response to Draft Decision, pp.101-102. Multinet noted that if this principle were not adopted, it the assumption about capital expenditure in 2002 would need to be updated. As the Commission has adopted its proposed fixed principle, it has not addressed Multinet's alternative position.

- any ongoing operations and maintenance costs due to FRC and *not recovered* as prices, fees or charges under the OIC [emphasis added] to be reflected in reference tariffs for the third access arrangement period.[455]

The distributors' proposed fixed principle clarifies that in 'any outstanding capital amount' means any FRC capital costs approved under the OIC that have not been recovered by the prices, fees and charges determined by the Regulator under section 12 of the OIC. Multinet and TXU have also specified that it is the *present value of any costs* associated with any outstanding capital amount that should be recovered.

In its submission accompanying its proposed Revisions, Multinet indicated that the purpose of this proposed fixed principle was to provide greater certainty and to simplify recovery of outstanding FRC costs by enabling 'any recoverable cost outstanding at the end of the second access arrangement period to be included in the calculation of the reference tariffs for the commencement of the third access arrangement period'.[456]

Envestra indicated that the FRC fixed principles are designed to reflect the fact that, amongst other things, not all costs associated with FRC may be recovered by 31 December 2007, and that there will be ongoing costs associated with FRC beyond 1 January 2008.[457]

RESPONSE TO DRAFT DECISION

As noted above, in the Draft Decision the Commission proposed to require each of the distributors to delete the proposed fixed principle on the basis that the FRC Order in Council already provided a framework for the recovery of FRC costs.

In response, each of the distributors argued that the Commission had not provided sufficient reasons to justify deleting the proposed fixed principle, and sought further clarification as to whether costs associated with FRC would be included in the third access arrangement period or as an adjustment to the opening asset base in 2008, including compensation for the capital costs over 2003-07.[458]

Multinet argued that:

> Systems and processes established, and for which cost recovery has been provided, under the OIC will need to be operated, maintained and enhanced so long as those systems and processes are required. Multinet requires certainty as to how such costs are to be recovered given the Regulator's intent to finalise the OIC in 2007. Multinet considers that the inclusion of such costs going forward post 2007 into the Access Arrangement process is the most appropriate mechanism.[459]

---

455 TXU, Reference Tariff Policy, clause 7.2(5), Multinet, Reference Tariff Policy, clause 7.2(4); Envestra, Reference Tariff Policy, clause 7.1(3). Note that clause 7.1(3)(B) of Envestra's proposed fixed principles provides for the recovery of 'any ongoing non-capital costs due to FRC *previously recovered* as prices, fees or charges under the OIC' rather than 'not recovered'. As discussed further below, the Commission understands both of the principles to carry the same intention, but considers that the intent of each expression should be improved.

456 Multinet, Access Arrangement Information, p.67.

457 Envestra, Access Arrangement Information, p.52.

458 TXU, Response to Draft Decision, p.39.

459 Multinet, Response to Draft Decision, p.103.

Envestra argued that the Commission's currently proposed mechanisms do not provide sufficient certainty that all of its FRC costs will be recovered:

> During the next 5 years the costs associated with FRC will be recovered through a separate Order In Council. Cost recovery under that process will cease in 2007. There will be ongoing costs associated with meter reading and FRC beyond that date and Envestra requires certainty about recovery of those costs. This lack of certainty is likely to result in a less efficient transition to the next regulatory period with ultimately higher costs for consumers.[460]

It should be noted that in response to the Draft Decision, Multinet has proposed amending its proposed fixed principle to read:

> The inclusion of forecast capital and non-capital costs for or in connection with, or in relation to, the implementation and operation of the Retail Gas Market Rules.[461]

FURTHER ANALYSIS

The FRC Cost Recovery OIC provides a process for distributors to seek to recover certain *unanticipated* costs and charges incurred in the implementation and operation of FRC through additional prices, fees or charges. Under the OIC process, the Commission is required to approve capital and operating expenditure for each distributor, and to set charges to permit recovery of these costs (in annualised form) over the period between the commencement of FRC and the end of 2007. An annual adjustment process will ensure that the charges set under the OIC permit the recovery of those annualised costs. As part of this annual mechanism, the distributors may propose additional expenditure not already approved by the Commission, which must then be justified against the cost recovery principles of the OIC.

The distributors' further responses to the Draft Decision clarify that the purpose of the fixed principle appears to be to provide them with certainty in relation to any costs that have been approved *but not yet recovered* through prices, fees or charges determined and approved by the Commission, and to continue to recover the cost associated with continuing obligations after the end of 2007. While these costs had been recovered under separate charges under the OIC up until 2007, the distributors will lose the ability to levy a charge in addition to the reference tariff from that point onwards.

The Commission accepts that part of the capital expenditure approved under the OIC may not have been recovered by the end of 2007, and that the distributors will still be required to perform functions that relate to operating expenditure approved under the OIC after the end of 2007 (such as meter reading). Clearly, it is appropriate that the distributors be permitted to factor such costs into the reference tariffs for the third access arrangement period.

---

460 Envestra, Response to Draft Decision, p.10.
461 Multinet, Response to Draft Decision, p.103.

Since releasing the Draft Decision, the Commission has released its Final Determination on the gas distributors' recoverable FRC expenditures.[462] In that Determination, the Commission confirmed the approach it proposed to take with respect to over- or under-recovery of revenue and operating expenditure over the period to 31 December 2007. In particular, it stated that each distributor would be required to provide audited information on operations and maintenance expenditure, revenues and fee structures for all previous years, and would consult further on the treatment of any over- or under-recovery that exists at that point in time, in accordance with clause 14 of the FRC Cost Recovery Order. It noted that any residual over- or under-recovery would need to be remedied through the reference tariffs in the third access arrangement period.[463] Clearly, therefore, there is a need also for reference tariffs to take account of any residual over- or under recovery.[464]

The Commission considers it reasonable to provide the distributors with certainty that they are able to recover capital expenditure approved under the OIC that has not been recovered by the end of 2007, recover operating expenditure associated with activities that relate to costs approved under the OIC, and for any residual over- or under-recovery to be factored into those reference tariffs. Accordingly, the Commission proposes to accept the distributors' proposed fixed principle, subject to an amendment that clarifies that the intent of the clause is to require:

- any outstanding capital costs at the end of 2007 that were approved under the OIC to be included in the capital base;
- reference tariffs for the third access arrangement period to reflect the cost associated with functions that relate to operating expenditure that was approved under the OIC; and
- reference tariffs for the third access arrangement period to reflect any residual correction for over- or under-recovery of revenue or operating expenditure over the period to the end of 2007, pursuant to clause 14 of the OIC.

AMENDMENT REQUIRED

Each of the distributors is required to amend its proposed fixed principle such that:

- **any outstanding capital costs at the end of 2007 that were approved under the OIC to be included in the capital base;**
- **reference tariffs for the third access arrangement period to reflect the cost associated with functions that relate to operating expenditure that was approved under the OIC; and**
- **reference tariffs for the third access arrangement period to reflect any residual correction for over- or under-recovery of revenue or operating expenditure over the period to the end of 2007, pursuant to clause 14 of the OIC.**

---

462 Gas full retail competition, Recoverable expenditure, operations and maintenance expenditure and setting of prices, fees and charges, Final Determinations – Envestra, Multinet and TXU, 30 August 2002.

463 pp.123-124

464 The Commission intends to consult further as to how best to align the assessment of such over- and under-recoveries in the next 2008 Access Arrangement Review.

Recovery of FRC costs not previously approved

DISTRIBUTORS' PROPOSALS

Each of the distributors has also proposed a fixed principle that would require the following:

> Where prudent, efficiently incurred capital and non-capital costs required to ensure the Service Provider has the capability to implement FRC within the timeframe prescribed by the Government have not been recovered either through:
>
> (A) arrangements for recovery of costs under the Cost Recovery OIC (dated 15 November 2001); or
>
> (B) Reference Tariffs established under this Access Arrangement;
>
> the Regulator will permit the present value of these costs to be recovered through Reference Tariffs for the Third Access Arrangement Period.[465]

Envestra also specified that the recovery of these costs would include 'an interest component set at the weighted average cost of capital applied to the capital base in the access arrangement period in question in reference tariffs for the third access arrangement period'.

In its original submission, Multinet indicated that the purpose of this principle was to provide for the recovery of prudent and efficiently incurred costs associated with the implementation of FRC that the service provider had not been able to recover through another mechanism.[466] Similarly, Envestra appeared to indicate that the purpose of the fixed principle was to allow costs associated with FRC to be recovered from users.[467]

DRAFT DECISION

In the Draft Decision, the Commission noted that there are two mechanisms available to distributors to seek recovery of costs associated with the introduction of FRC namely:

- the FRC Cost Recovery Order in Council that allows distributors to recover certain *unanticipated costs* incurred in the 2003-07 access arrangement period (ie. up to and including 2007); and
- through reference tariffs determined as part of the review of the distributors' proposed Revisions.

Given that the expenditure benchmarks that were factored into the reference tariffs in the Draft Decision were designed such that there were no required functions or obligations that would fall between these two mechanisms, the Commission required that this clause be deleted.

In response, Envestra argued that:

465 Multinet, clause 7.2(a)(5); TXU, clause 7.2(a)(6); Envestra 7.1(e)(4).
466 Multinet, Access Arrangement Information, p.67.
467 Envestra, Access Arrangement Information, p.52.

> The Code contains principles that provide for businesses to be given the opportunity to recover the reasonable and prudent non-capital costs associated with providing all Services and for the recovery of new facilities investment that passes the test in section 8.16 of the Code. [It] therefore believes that its proposed Fixed Principle is consistent with the Code in that it is the only way for Envestra to ensure that all its legitimately incurred costs associated with FRC can be recovered.[468]

Multinet explained that:

> Costs associated with the implementation of FRC are categorised as anticipated and unanticipated with the latter being recovered under the FRC Order mechanism. Logically, if a cost is not unanticipated, then it must be anticipated. Distributors have, and will continue to incur costs associated with FRC that are not unanticipated, therefore they are said to be anticipated. The only mechanism available to distributors is to claim such costs under the Access Arrangement mechanism.
>
> Multinet maintains that the Total Revenue requirements set for the First Access Arrangement Period did not provide sufficient allowance for anticipated costs associated with FRC. It has claimed these costs (excluding the unanticipated component) as scope changes for the First Period. For the Second Access Arrangement Period it has included identified expenditure for the anticipated component of FRC in its Capital and Operating expenditure.[469]

FURTHER ANALYSIS

The expenditure benchmarks that have been adopted in this Final Decision include an allowance in respect of any activity that the distributors would have to perform in relation to the implementation of FRC for which the cost would not be recoverable under the OIC. Accordingly, the reference tariffs that have been determined for the 2003-07 access arrangement period are based on the assumption that there is no cost that would fall within the scope of the fixed principle described above. The Commission's reasons for the expenditure benchmarks, including the assumptions made about FRC-related activities, are set out in sections 3.2 and 3.3.

As the OIC and reference tariffs adopted in this Final Decision collectively make provision for the cost of all of the activities required to implement FRC, the Commission considers that such a clause is not required to ensure that objective in section 8.1(a) of the Gas Code is met. However, the Commission is concerned that the fixed principle set out above would invite the distributors to seek to recover any unfavourable difference between the forecast and actual amount on the activities for which an allowance has been included in reference tariffs, which would reduce their incentives to be efficient (thus being inconsistent with the objective set out in section 8.1(f) of the Gas Code.

On balance, for the reasons above, the Commission considers that the fixed principle set out above does not meet the requirements of the Gas Code. Accordingly, the Commission requires each of the distributors to delete the proposed fixed principle.

468 Envestra, Response to Draft Decision, p.10.
469 Multinet, Response to Draft Decision, p.104.

AMENDMENT REQUIRED

Each of the distributors is required to delete the proposed fixed principle allowing it to recover prudent and efficiently incurred costs associated with the implementation of FRC that it has not been able to recover through another mechanism.

5.1.10 Retailer of last resort obligations

Each of the distributors has proposed a fixed principle that allows them to use the proposed change in tax pass-through provisions to recover the costs associated with their obligations under the Gas Retailer of Last Resort (RoLR) provisions of the Gas Industry Act.[470] The distributors have proposed to fix these principles until the end of the third access arrangement period.

Specifically, the relevant fixed principle for Multinet and TXU provide that reference tariffs in the third access arrangement period will provide for:

> The inclusion of the present value of costs incurred to comply with section 34 of the GIA which relates to obligations as a Gas Retailer of Last Resort (RoLR) or any guidelines or consultation papers issued by the Regulator which relate to obligations as a RoLR.[471]

Multinet indicated that the purpose of this proposed fixed principle is to ensure that it is able to recover costs incurred as a result of the implementation of a RoLR scheme, which might arise as a result of an obligation or any guidelines or consultation papers issued by the regulator on ROLR issues.[472]

Envestra proposed a similar fixed principle and noted that it would seek to recover these costs via the change in tax pass-through provisions:

> Costs incurred in complying with section 34 of the GIA (which relates to obligations as a Gas Retailer of Last Resort (RoLR)) or any guidelines or consultation papers issued by the Regulator which relate to obligations as a RoLR will be passed through to Users via an increase in Reference Tariffs, in accordance with the procedures established in section 8 for a Change in Taxes Event.[473]

In its submission accompanying its proposed Revisions, Envestra noted that it had not included any allowance for these obligations in its expenditure forecasts for the 2003-07 access arrangement period because of the uncertainty about what these obligations may require. It also noted that its preference was to recover these additional expenses via the change in tax pass-through mechanism, as this would provide the regulator with the opportunity to review these costs and consider the basis on which the costs would be passed through.[474]

---

470 Section 34.
471 Multinet, clause 7.2(a)(7); TXU, clause 7.2(a)(8).
472 Multinet, Access Arrangement Information, 28 March 2002, p.67.
473 Envestra, clause 7.1(e)(6).
474 Envestra, Access Arrangement Information (Victoria), 2 April 2002, p.53.

In the Draft Decision, the Commission proposed to require the distributors to delete the fixed principles, on the basis that it considered that the FRC Order provides a framework for the recovery of FRC costs and includes a requirement for the Commission to make determinations with respect to cost recovery.

RESPONSE TO DRAFT DECISION

In response to the Draft Decision, each of the distributors expressed concern about the magnitude of costs that they may be required to incur during the 2003-07 access arrangement period arising from a potential ROLR event and sought greater clarity from the Commission as to how it envisaged the distributors would be able to recover such costs.

Multinet reiterated that the proposed fixed principle is intended to provide it with some certainty that it will be able to recover costs for such events that are clearly outside its control. In particular, it argued that:

> … should a ROLR event occur, distributors may be required to respond to assist any retailer undertaking such a role to establish its systems and will be required to make amendments within its own systems. It may also face financial exposures arising from the failure of the existing retailer.[475]

Multinet indicated that in the absence of such a fixed principle, it should be incumbent on the regulator to provide some alternative form of certainty to how it would recover ROLR related costs, should they arise.

Similarly, Envestra noted that costs associated with a ROLR event might occur at any time, regardless of whether FRC occurs. As a result, it does not consider that there is necessarily a link between ROLR costs and FRC. Further, it noted that due to the uncertainty about the magnitude of costs associated with a potential ROLR event, it has not included any forecasts of the operating costs associated with these events.[476]

Envestra argued that there are no other mechanism in place for it recoup any costs that may arise, should a ROLR event occur.[477] As a result, it considers that the most appropriate way to deal with these costs is for them to be passed through to customers within the access arrangement period, through the change in tax pass-through provisions. In doing so, it argued that the Commission would have the opportunity to review these costs, including the basis on which the costs would be passed through to customers.

FURTHER ANALYSIS

Section 34 of the *Gas Industry Act 2001* enables gas distribution or retail licence holders to be asked to act as a retailer of last resort (RoLR) and provides for the Commission to develop the detailed framework for implementing the RoLR solution.

[475] Multinet, Response to Draft Decision, p.106.
[476] Envestra, Response to Draft Decision, p.10.
[477] ibid, p.10.

The Commission is currently in the process of consulting on the detailed framework to give effect to the RoLR scheme. This includes considering whether distributors or retailers would be in the best position to act as the RoLR in the event that a second tier gas retailer makes an unplanned market exit.[478] In an earlier consultation paper on the issue, the Commission expressed its preference for host retailers to act as the ROLR on the basis that they would most likely be in the best position to provide such services. Most of the submissions received in response to the consultation paper appeared to support this approach.

The Commission is still in the process of considering the exact nature of the RoLR arrangements to apply, and proposes to release a Draft Decision on the issue in October 2002. Irrespective of whom the Commission decides should act as RoLR, the distributors may have a role. However, the precise role of the distributors also depends upon the exact nature of the RoLR arrangements, particularly the question of whether the distributors are required to implement up-front systems to keep the customer data required to respond to a RoLR event, or whether distributors would only have a role should a RoLR event arise.

In any event, the Commission accepts that it would be appropriate to provide the scope (and certainty) for distributors to recover costs associated with any additional RoLR obligations imposed on them over the 2003-07 access arrangement period. It also accepts that this cost pass-through should relate both to the cost of any up-front activities required (such as installing systems, should such an obligation be imposed), and to the cost of responding to a RoLR event (should such an event arise).

On the issue of how such costs should recovered, the Commission notes that the distributors appear to have proposed alternative approaches. For example, Envestra has proposed that recovery of such costs occur via the change in tax pass-through mechanism, whereas TXU's and Multinet's proposed revisions appear to be indicate that such costs would be recovered through reference tariffs in the third access arrangement period.

The Commission considers that the most appropriate mechanism for seeking to recover any additional costs incurred in the 2003-07 access arrangement period associated with RoLR obligations is the change in tax pass-through mechanism (see section 5.1.10). This will enable distributors to seek to pass through the costs associated with RoLR within the access arrangement period, rather than delay the recovery of those costs until the third access arrangement period (as proposed by Multinet and TXU).

In relation to the recovery of any ongoing costs associated with implementing RoLR obligations beyond the second access arrangement period, the Commission considers that a mechanism for recovering these costs would most appropriately be dealt with in the context of considering the Revisions to apply in the third access arrangement period.

---

478 Essential Services Commission, Consultation Paper, Gas Retailer of Last Resort, February 2002, p.16.

In view of these considerations, and given the Commission's consequential amendment to the distributors' proposed change in tax and relevant tax definitions (see section 4.8), the Commission does not consider that it is necessary or appropriate to include a fixed principle for the third access arrangement period that allows distributors to recover costs associated with any ROLR obligations. Accordingly, it requires the proposed fixed principle to be deleted from the distributors' proposed Revisions. However, the Commission reiterates that this deletion reflects the fact that its amendment to the change in tax definitions already provides the scope (and certainty) for recovery sought by the distributors.

AMENDMENT REQUIRED

Each of the distributors is required to delete the proposed fixed principle related to the recovery of costs associated with retailer of last resort obligations.

5.1.11 Changes to the Gas Code

In their proposed Revisions, each of the distributors proposed a more general fixed principle that would potentially allow them to unilaterally delete one or more of the fixed principles in the event of a change to the Gas Code. Specifically, each of the distributors proposed the following fixed principle:

> If the Access Code is amended so that:
>
> (1) there is no longer a requirement for the Regulator and the Service Provider to adopt and be bound by some or all of the Fixed Principles in the Service Provider's Access Arrangement; and/or
>
> (2) one or more of the Service Provider's Fixed Principles becomes or may be construed as being inconsistent with the amended Access Code;
>
> *the Service Provider may, at its absolute discretion, delete one or more of the Fixed Principles* set out in [the relevant section of each distributors' proposed Revisions dealing with fixed principles] for application in the Fixed Period, to the extent that such decisions are not or do not thereby become inconsistent with the amended Access Code. *[emphasis added]*[479]

In the Draft Decision, the Commission proposed to require each distributor to delete this proposed fixed principle on the basis that it enabled them to use their *absolute discretion to delete one or more of the fixed principles* without the need for such a revision to the Access Arrangement to be subject to public and access arrangement scrutiny, as required by the consultation and approval processes of the Gas Code. In particular, the Commission raised the following concerns in relation to the proposed fixed principle:

- it reduces the level of certainty associated with the operation of the fixed principles and other provisions of the Access Arrangement;

[479] Multinet, clause 7.2(b); TXU, clause 7.2(b); Envestra, clause 7.1(e)(7).

- it reduces transparency and removes the need to consider the interests of users, and allow industry stakeholders the opportunity to comment through a transparent process; and
- it may adversely impact on the operation and effectiveness of other aspects of the distributors Access Arrangements, which will not potentially be identified through a consultation process.

In response to the Draft Decision, the distributors emphasised that an amendment to the Code provides the possibility for a number of the fixed principles to become either inconsistent with or redundant to the Code.

For example, Multinet commented that given the likelihood of a review and subsequent amendment of the Gas Code over the 2003-07 access arrangement period:[480]

> … it is not unreasonable to expect that as a result of an amendment to the Access Code some aspects of the Fixed Principles, as drafted, may become either redundant or at the minimum, conflict with aspects of any Access Code Revision. Multinet remains strongly of the view that it is reasonable, and may indeed overcome potential anomalies and inconsistencies, to retain at least part of this Fixed Principle. That is, if the Access Code is amended in such a way that any one or more of the Fixed principles in the Multinet Access Arrangement Revision becomes inconsistent with Access Code, then the affected Fixed Principles can be deleted without affecting or tainting the remainder of the Access Arrangement Revision.[481]

Whilst Envestra did not necessarily agree with the Commission's views, it proposed to amend the wording of the fixed principle in order to increase certainty for users. However, at the same time it noted that:

> … it is clear that if the Gas Code is amended then neither Envestra nor Users should be bound by Fixed Principles that are inconsistent with the regulatory regime. And in such circumstances Envestra believes there is no need to subject the deletion of the clause to public consultation, as the need for deletion is self-evident. [482]

TXU did not comment on the Commission's Draft Decision, but along with the other distributors, it proposed the following alternative wording:

> if the Access Code is amended so that one of more of the Service Provider's Fixed Principles becomes or may be construed as being inconsistent with the amended Access Code, the Service Provider may, *if in the Service Provider's reasonable view it is necessary to do so in order to overcome, or reduce the effect of, that inconsistency,* delete one or more of the Fixed Principle set out in clause 7.2(a) for application in the Fixed Period, to the extent that such deletions are not or do not thereby become inconsistent with the amended Access Code, *and the deletion will become effective five (5) business days after written notice of the deletion is provided to the Regulator.*[483]

480 Multinet, Response to Draft Decision, p.107.
481 ibid., p.108.
482 Envestra, Response to Draft Decision, p.20.
483 Multinet, Response to Draft Decision, p.108; TXU, Response to Draft Decision, p.41; Envestra, Response to Draft Decision, p.20.

Whilst the Commission accepts that the intent of the proposed fixed principle may be to remove any potential inconsistency or conflicts that may arise as a result of changes to the Gas Code, it does not consider that the distributors' alternative wording to the fixed principle sufficiently addresses the Commission's concerns. In particular, the Commission remains concerned that an amendment to the Revisions will not be subject to any form of consultation as required under the Gas Code. Further, in view of the linkages between various aspects of the distributors' Access Arrangements and the incentive properties of the regime, it would not allow the Commission, users and the distributors themselves the opportunity to consult on the implications of deleting any of the fixed principles. Neither does it allow for a full and proper consideration of the best way of overcoming the inconsistency or dealing with any issues associated with deleting the fixed principles.

The Commission reiterates that the Gas Code provides for distributors to propose amendments to their Access Arrangements at any time, and to submit them to the Commission for approval, in accordance with the consultation and approval provisions of the Gas Code. As a result, if the distributors feel that any amendments to the Gas Code result in inconsistencies, it may still seek to have the implications of the changes considered.

The Commission does not consider that the proposed amendment is consistent with section 8.48 of the Gas Code, which requires it to consider the interests of both the service provider and users and prospective users in revising the Access Arrangements. Therefore, the Commission remains of the view that the distributors should delete their proposed fixed principles allowing them to delete any fixed principle in the event of a change to the Gas Code.

AMENDMENT REQUIRED

Each of the distributors is required to delete their proposed fixed principle allowing them to delete one or more of the fixed principles to reflect amendments to the Gas Code.

5.2 Review and expiry of the Access Arrangements

Under section 3.17 of the Gas Code, an Access Arrangement must include:

- a date upon which the service provider must submit Revisions to the Access Arrangement to the regulator for approval (revisions submission date); and
- a date upon which the next Revisions are intended to commence (Revisions commencement date).

Each of the distributors proposed a revisions submission date of 30 March 2007, providing a period of nine months to assess and implement the proposed Revisions, and a revisions commencement date of 1 January 2008.

5.2.1 Draft Decision

In the Draft Decision, the Commission noted that the Tariff Order defines the second access arrangement period to be the period of five calendar years from 1 January 2003. This implies a Revisions commencement date for the Victorian access arrangements of 1 January 2008. Whilst Envestra is not required to comply with the same Tariff Order requirements for its Albury Revisions, it has also proposed the same commencement date, which the Commission considers provides it with scope to achieve greater synergies and efficiencies in the operation and management of both networks. Accordingly, in the Draft Decision, the Commission proposed to accept the Revisions commencement date proposed by each distributor.

In the Draft Decision, the Commission proposed to require the distributors to amend their proposed revisions submission date of 30 March 2007 to 31 January 2007 on the basis that its experience suggested that other regulatory or implementation issues often arise that must be dealt with prior to the commencement of the proposed arrangements, and that a period of three months may not provide a sufficient contingency to deal with such matters. It also noted that, in view of the complex matters that regulators are required to consider and consult on, most decisions made by jurisdictional regulators under the Gas Code have been extended beyond the initial six-month period. In light of this and the desirability of ensuring that there is sufficient time allowed after the revisions submission date to consult, decide and implement the proposed Revisions, the Commission considered that it would be prudent to extend the Revisions submission date by a further two months.

5.2.2 Responses to Draft Decision

In response to the Draft Decision, each of the distributors argued that bringing forward the revisions submission date by a further two months to 31 January would result in a number of practical difficulties including:

- key information for the preceding calendar year would be unlikely to be available at the time the submissions are being prepared, resulting in less than four years of complete data being captured in the proposed Revisions;[484]
- for listed companies, the financial data cannot be released until after it has been presented to the market in mid February of the fifth year[485]; and
- difficulties associated with trying to complete a submission and acquire the necessary resources over the Christmas break.[486]

---

484 Envestra, Response to Draft Decisionp.19. TXU, Response to Draft Decision, p.40. Multinet, Response to Draft Decision, p.99.

485 Multinet, Response to Draft Decision, p.99.

486 Envestra, Response to Draft Decisionp.19.

Multinet noted that section 2.44 of the Gas Code already provides the Regulator with the flexibility to extend its review period beyond the initial six month period should it consider it necessary to do so. Whilst the Commission accepts that the Gas Code does provide scope to extend the decision-making period, this has the potential to delay the revisions commencement date, and thereby contributes to greater uncertainty. It is this uncertainty and risk of delaying the revisions commencement date that the Commission was seeking to avoid in its Draft Decision requirement to bring forward the revisions submission date.

TXU also suggested that the next review process should impose less time demands because of the experiences of the 2003-07 access arrangement period, including settling the current added complexities of FRC and simplifying the regulatory framework and instruments. In addition, both TXU and Multinet argued that it would be more appropriate for the Commission to consider undertaking a similar preliminary consultation process (as it did for this review), rather than bringing further forward the formal revision submission date.[487]

5.2.3 Final Decision

The Commission accepts the distributors' argument that bringing forward the revisions submission date to 31 January 2007 may compromise the ability to undertake the next review of gas Access Arrangements having regard to the best available and most complete information. In particular, it may limit the extent to which the Commission may have regard to four full years of data, which may increase the difficulty of assessing the distributors' performance against the benchmarks for the 2003-07 access arrangement period as well as assessing whether the proposed forecasts represent best estimates derived on a reasonable basis. Accordingly, the Commission does not require the distributors to revise their proposed revisions submission date.

However, the Commission reiterates that there remains a risk that allowing nine months from the revisions submission date to the commencement of the new revisions may not sufficiently provide for consultation and issues associated with the implementation of the revised Access Arrangements. Whilst it accepts that there may be increasingly less contentious issues at the time of the next review and that matters related to the regulatory framework may be more settled then, there remains a risk that issues may emerge which increase the likelihood of the revisions not commencing as per the proposed date. This is likely to contribute to greater uncertainty for distributors, users and prospective users about the precise arrangements to apply from 1 January 2008.

The Commission notes the comments made by various distributors that these risks could to some extent be managed by undertaking a consultation process in advance of the formal revisions submission date, as the Commission has done for this review.

[487] TXU, Response to Draft Decision, p.41.

In view of the distributors' support for preliminary consultation, the Commission will give further consideration to undertaking early consultation on the key issues associated with the next review. However, it notes that the value of undertaking preliminary consultation to reduce the risk that the formal review consultation process will not be completed in time for the revision commencement date relies on the active participation of both distributors and users.

5.3 Capacity management and trading policy

Section 3.7 of the Gas Code requires an Access Arrangement to include a statement indicating whether the covered pipeline is either a contract carriage pipeline or a market carriage pipeline. To the extent that access is offered on a contract carriage basis, then the Code requires that the Access Arrangement include a policy on the trading of capacity.[488]

Each of the distributors' existing Access Arrangements indicates that the distribution system is a market carriage pipeline, and this approach is continued in the proposed Revisions. Accordingly, the provisions relating to the need to include a trading policy are not relevant.

In the Draft Decision, the Commission expressed the view that the differences between a contract carriage system and a market carriage system are not particularly marked for a distribution system. In addition, the distribution systems do not appear likely to face constraints in the medium term, and as a result, the creation of a capacity trading system is unlikely to deliver many benefits. As a result, it considered that the ongoing approach of structuring the distribution system as a market carriage system was appropriate.

There were no comments received in response to the Draft Decision in relation to the distributors' proposed capacity management and trading policy. As a result, the Commission remains of the view that the distributors' proposed capacity management and trading policies are appropriate.

5.4 Queuing policy

Section 3.12 of the Gas Code requires that an Access Arrangement include a policy for determining the priority that one prospective user has against another to obtain access to spare and developable capacity where it is not possible to accommodate both. Section 3.13 also states that the queuing policy must:

- set out sufficient detail to enable users and prospective users to understand in advance how the queuing policy will operate;
- accommodate, to the extent reasonably possible, the legitimate business interests of the service provider and of users and prospective users; and
- generate, to the extent reasonably possible, economically efficient outcomes.

488 Section 3.10 of the Gas Code.

In addition, the regulator may require the queuing policy to deal with any other matter that it thinks fit taking into account the matters outlined in section 2.24 of the Gas Code.

5.4.1 Distributors' proposals

Both TXU and Multinet have indicated that the queuing policy is applicable to requests for new connections or modifications to existing connections and is subject to the extensions and expansions policy. In addition, their proposed Revisions set out the following procedure for dealing with requests for modification of an existing connection:

- it will administer requests in the order they are received (on a 'first come, first served' basis), including advising the prospective user as to the charge (if any) for undertaking or modifying the connection; and
- it may amend the charge first specified prior to the connection being made, if additional requests for undertaking or modifying a connection are received and those additional requests allow the recovery of the charge over a larger or different group of user or prospective users.

In its Access Arrangement Information, Envestra expressed the view that it is more efficient for capacity expansion to take account of the aggregate requests. This requires the priority to be given to individual users to permit these efficiencies to be captured. Accordingly, Envestra's proposed Revisions for both Victoria and Albury state that requests from prospective users will be processed in the order they are received subject to:

> Where there is sufficient Spare Capacity available in the Distribution System to meet the needs of a Prospective User (who is at the top of the queue) at a nominated point in the Distribution System, Envestra will offer the Spare Capacity at that point in the Distribution System to that Prospective User.
>
> Where there is insufficient Spare Capacity available at a nominated point in the Distribution System to meet a Prospective User's request (having reached the top of the queue), Envestra will first offer that Prospective User any Spare Capacity that is capable of partly satisfying its request at that nominated point. The Service Provider may then undertake an investigation of Developable Capacity alternatives. Under these circumstances, Envestra may elevate the priority of other Prospective Users' requests affected by the proposed augmentation in the interests of optimising design and achieving efficiency in the structure and level of Reference Tariffs. The Service Provider will only take such action where it is reasonable to do so and where it will not foreseeably disadvantage other Prospective Users, other than in relation to their position in the queue.[489]

5.4.2 Draft Decision

In the Draft Decision, the Commission proposed to require each distributor to amend its proposed Revisions to ensure that:

---

489 Envestra, Access Arrangement (Victoria and Albury), clause 5.52.

- users and prospective users are kept informed of their position in the queue and any other developments that are likely to affect the timing of satisfying their capacity request including the cost associated with that capacity; and
- where a distributor extends part of the network in response to the requests of a number of users or prospective users, the charges levied by the distributor for that additional capacity should reflect the lower unit costs resulting from the recovery of charges across a number of users or prospective users.

5.4.3 Responses to Draft Decision

In response to the Draft Decision, a number of the distributors argued that the queuing policy provisions of the Gas Code are not necessarily relevant to gas distribution systems, and more relevant to gas transmission. TXU argued that queuing is not a significant issue for the Victorian gas distribution system and referred to the considerable debate that had occurred on this issue in the consultation leading to the approval of the existing Access Arrangement.[490] Similarly, Multinet expressed the view that whilst it has complied with the Gas Code requirement to include a queuing policy, it considers the requirement unnecessary in the distribution system context.[491]

Multinet also noted that National Gas Pipeline Advisory Committee (NGPAC) had recently agreed to delete the requirement from the Gas Code for gas distribution service providers to include a queuing policy in their Access Arrangements, and that the amending agreement to the Gas Code to give effect to this resolution was awaiting complementary legislative amendment.

Nevertheless, each of the distributors generally accepted the Commission required amendment that users and prospective users are kept informed of their position in the queue and any other developments.

In addition, Envestra proposed the following clause to give effect to the required amendment:

> Where a User or Prospective User enters a queue and the Service Provider is unable to satisfy the capacity request within an agreed timeframe, the User or Prospective User shall be kept informed of their position in the queue and, developments that affect their position in the queue; or materially affect the anticipated cost of the provision of capacity.[492]

In contrast, TXU argued that its proposed queuing policy is unchanged from its existing Access Arrangement and it considered that circumstances had not changed to the effect that it now required amendment. Accordingly, it did not consider that it should be required to adopt revisions it has not sought.[493]

490 TXU, Response to Draft Decision, pp.41-42.
491 Multinet, Response to Draft Decision, p.110.
492 Envestra, Response to Draft Decision, p.22.
493 TXU, Response to Draft Decision, p.41.

In relation to the Commission's second required amendment, both TXU and Envestra expressed the view that the issue of charges for additional capacity reflecting the lower unit costs is not a matter that should be dealt with in the queuing policy.[494] Multinet also argued that the required amendment is unnecessary as section 5.5.2(a)(2) of its proposed queuing policy already covers the issue of recovery of charges across a number of users or prospective use.[495] In addition, Envestra expressed the view that this requirement was unnecessary, as the extension and expansion policy already deals with the effect of extensions on tariffs.[496]

5.4.4 Final Decision

The Commission acknowledges that NGPAC appears to have agreed to remove the requirement for gas distributors to include a queuing policy in their Access Arrangements, on the basis that it appears to be a more relevant issue for gas transmission rather than distribution. However, at the time of finalising this Decision, this code change has yet to be given legal effect.

As a consequence, at this point in time, the Commission is required to be satisfied that the distributors' Access Arrangements include all of the elements included in section 3.1 to 3.20 of the Gas Code, which includes a requirement to include a queuing policy and to be satisfied that the queuing policy satisfies the requirements of the Gas Code.

Nevertheless, the Commission accepts that there is a diminished continuing need to amend the distributors' proposed queuing policies given the likelihood of the Gas Code changes taking effect. Accordingly, whilst the Commission requires the distributors to still include a queuing policy in their revised Access Arrangements at this stage, it does not require the distributors to amend the proposed Revisions to give effect to the previously required amendments.

494 ibid, p.42.
495 Multinet, Response to Draft Decision, p.110.
496 Envestra, Response to Draft Decision, p.22.

Appendix A The Commission's review process

This Appendix sets out the key elements of the Commission's public consultation process related to this review of the distributors' proposed Access Arrangements Revisions.

A.1 Overview of consultation process

The Commission has provided a number of opportunities for the gas distributors and other interested parties to express their views about matters related to this review. This has included consultation in relation to the Commission's proposed approach and process, as well as the detailed analysis and assessment of the distributors proposals against the relevant provisions of the Gas Code.

In developing this Final Decision, the Commission has taken into account the information submitted by the distributors', the views expressed by interested parties throughout the Commission's consultation process, as well as other information and analysis by the Commission and its advisers.

The table below summarises the key elements of the Commission's consultation process undertaken over the course of this review.

TABLE A.1
THE COMMISSION'S CONSULTATION PROCESS

Date	Process
16 May 2001	Release of Consultation Paper No. 1
1 July 2001	Submission due date for responses to Consultation Paper No. 1
13 July 2001	Workshops: service standards and price controls/tariffs
17 July 2001	Workshops: efficiency incentives and cost of capital financing issues
9 August 2001	Workshops: regulatory instruments
7 September 2001	Release of Position Paper
26 October 2001	Due date for distributors to submit preliminary proposals
20 December 2001	Release of Further Guidance to Gas Distributors paper
2 April 2002	Receipt of proposed Access Arrangement Revisions and accompanying Access Arrangement Information from Envestra (Victorian network), Multinet and TXU Networks
8 April 2002	Receipt of proposed Access Arrangement Revisions and accompanying Access Arrangement Information from Envestra (Albury network),
24 April 2002	Release of Summary Paper
End April-June 2002	Further clarification/request for information of distributors' proposed Access Arrangement Revisions by Commission and its advisers
4 July 2002	Release of Commission's Draft Decision
7 August 2002	Receipt of Submissions to Draft Decision
13 August 2002	Draft Decision Public Hearing
15 August 2002	Terms and Conditions Working Group meeting*
August- September 2002	Further clarification/request for information from distributors
2 October 2002	Release of Commission's Final Decision

*The distributors and retailers also met separately on 5 September 2002 to discuss the Terms and Conditions

Copies of the Commission's various consultation papers and other documents, including responses and comments from other interested parties are available on the Commission's website at www.esc.vic.gov.au.

A.2 Consultation undertaken prior to this review

In view of the tight timelines provided for consultation and decision-making under the Gas Code, in early 2001 the gas distributors and a number of other interested parties requested that the Commission conduct early consultation on a number of the substantive issues related to the review of proposed Access Arrangement Revisions. This was intended to ensure that, as much as possible, the distributors' proposed Revisions would reflect users' preferences and the requirements of the regulatory framework.

To this end, the Commission released a Consultation Paper in May 2001 identifying a number of issues that it considered warranted early and detailed consideration. The Commission received a number of submissions and conducted a series of workshops and meetings to provide a further opportunity for interested parties to debate the issues and express their views.

In September 2001, the Commission released a Position Paper outlining its preliminary views on a number of the key issues. The Position Paper incorporated comments and views expressed in submissions and at public workshops. The Commission invited comments and received responses from a number of gas distributors and other interested parties.

A number of stakeholders expressed the view that it would be useful if gas distributors provided an early indication of how they proposed to incorporate the matters discussed in the Position Paper into their proposed Access Arrangement Revisions. In late October 2001, each of the three gas distributors made submissions to the Commission that signalled to some extent the likely approach that each proposed to take in its Revisions in dealing with certain issues raised in the Position Paper. Submissions were also received from other interested parties in response to the Position Paper.

In response to the gas distributors' submission, the Commission issued a paper in December 2001 summarising the proposals and positions outlined in the gas distributors' and other submissions.[497] This paper also provided gas distributors with further guidance on a number of the key issues in order to assist them in preparing their formal Revisions.

In addition to consulting on these key issues, the Commission initiated separate processes for resolving a number of other matters: including developing a standardised set of terms and conditions for using the gas distribution system, establishing regulatory information guidelines, and revising the Gas Distribution System Code and Distribution Licences.

A.3 Receipt and consultation on the distributors' proposed Revisions

On 2 April 2002, the Commission received proposed Revisions to the existing Access Arrangements and Access Arrangement Information from the following entities operating gas distribution networks in Victoria:

- Multinet Gas (DB No.1) Pty Ltd and Multinet Gas (DB No.2) Pty Ltd (trading as 'Multinet Partnership');
- TXU Networks (Gas) Pty Ltd (formerly known as Westar); and
- Envestra licensed as Vic Gas Distribution Pty Ltd (formerly known as Stratus Networks).

On 8 April 2002, the Commission also received from Envestra proposed Revisions to the existing Access Arrangements and Access Arrangement Information in relation to its Albury distribution system.[498]

497 Op. cit., Further guidance to gas distributors.

498 In January 2002, the relevant State and Federal ministers under the *Gas Pipelines Access Act 1998* consented to cross-vesting jurisdiction to the Commission in relation to certain matters relating to the Albury Distribution System. While the Commission now has regulatory responsibility for access matters, the NSW legislation and licensing arrangements continue to apply under the regulatory control of IPART.

Under the Gas Code, the Commission is required to publish in a newspaper circulating nationally that it has received the proposed Access Arrangement Revisions and to invite submissions in response. In response to the receipt of the proposed Victorian Access Arrangement Revisions, the Commission published a notice in *The Australian* and *Australian Financial Review* newspapers on 4 and 5 April 2002 respectively. The notices called for written submissions to be made in response to the proposed revisions by 8 May 2002. Copies of gas distributors' proposed Revisions and other relevant information submitted were made available publicly on the Commission's website.

In relation to Envestra's proposed Revisions to its Albury Access Arrangements, the Commission published a notice of the receipt of the revision in the *Australian Financial Review* and the *Albury Border Morning Mail* on the 19 April 2002. The notice called for written submissions to be received by 20 May 2002.

To facilitate public consultation on the distributors' proposed Revisions, the Commission released a Summary Paper in April 2002 that summarised the key features of the distributors' proposed Revisions and invited public comment on those and other issues.

The Commission received the following submissions in response to the gas distributors' proposed Revisions.

TABLE A.2
SUBMISSIONS RECEIVED IN RESPONSE TO THE PROPOSED REVISIONS

Number	Name	Date received
1	Moyne Shire Council	7 May 2002
2	Multinet Gas	1 May 2002
3	Energex	8 May 2002
4	Pulse Energy	9 May 2002
5	Envestra	9 May 2002
6	TXU Retail	10 May 2002
7	Origin Energy	16 May 2002
8	TXU Retail (Albury)	20 May 2002
9	Overall Forge (Confidential)	17 May 2002
10	Origin Energy (Albury)	24 May 2002
11	Joint submission from large industrial customers[499]	30 May 2002
12	Gas customer[500]	17 May 2002

499 Joint submission prepared by Energy Advice Pty Ltd on behalf of ACI Glass Packaging, Barrett Burston, Bonlac Foods, Cabot, CSR Limited, Insulation Solutions, Mobil Altona Refinery, Norske Skog, Overall Forge, Pilkington Glass, Qenos, Tatura Milk.

500 The author of this submission has provided this submission on the basis that his/her name and contact details be kept confidential.

A.4 Submissions and consultation on the Draft Decision

On 4 July 2002, the Commission released its Draft Decision in relation to the gas distributors' proposed Revisions pursuant to section 2.35(b) of the Gas Code. In summary, the Commission proposed not to approve the gas distributors' proposed Revisions and set out the nature of amendments that the Commission required before it will approve them. It also set out the relevant issues, information and the analysis underpinning its Draft Decision.

The Commission invited public submissions in response to its Draft Decision to be provided by 5 August 2002. The submissions received in response to the Draft Decision are listed in the table below.

To provide a further opportunity for interested parties to comment on the Draft Decision and other issues, the Commission held a public hearing on Tuesday 13 August 2002 in Melbourne.

The Commission has also held meetings with the distributors and other interested parties on a number of occasions to provide and seek further clarification about issues and comments in relation to the Commission's analysis and assessment of the distributors' proposed Revisions.

TABLE A.3

SUBMISSIONS RECEIVED IN RESPONSE TO THE DRAFT DECISION

Number	Name	Date received
1	Origin Energy	5 August 2002
2	Energex Retail	5 August 2002
3	Trowbridge Consulting	5 August 2002
4	TXU Retail	5 August 2002
5	Customer[501]	5 August 2002
6	AGL	7 August 2002
7	TXU Networks	7 August 2002
8	Multinet Gas	7 August 2002
9	Moira Shire Council	9 August 2002
10	Australian Gas Association	9 August 2002
11	Envestra	9 August 2002
12	Customer Energy Coalition	23 August 2002
13	Origin Energy	23 August 2002
14	TXU Networks	23 August 2002
15	Energex Retail	26 August 2002
16	TXU Retail	26 August 2002
17	AGL	27 August 2002
18	Energy Users Coalition of Victoria	29 August 2002
19	Infrastructure Access Services	2 September 2002
20	Multinet Gas	3 September 2002
21	TXU Networks	3 September 2002
22	Envestra	3 September 2002
23	Energy Users Coalition of Victoria	6 September 2002
24	TXU Networks	6 September 2002
25	Australian Gas Association	6 September 2002
26	Joint Submission from Distributors	6 September 2002
27	Multinet Gas	6 September 2002
28	Multinet Gas	9 September 2002
28	Australian Gas Association	13 September 2002
29	Envestra	18 September 2002

501 This submission has provided on the basis that the author’s name and contact details be kept confidential.

Appendix B Terms and conditions

This appendix provides a detailed discussion of the key issues related to the terms and conditions of the distributor's revised access arrangements. The terms and conditions govern the legal relationship, rights and obligations between the distributors and retailers in relation to the supply of reference services and apply to non-reference services and services supplied by retailers to distributors (retail services).

B.1 Gas Code requirements

Under 3.6 of the Gas Code, the terms and conditions must, in the Commission's opinion, be reasonable. In determining whether the terms and conditions are reasonable, the Commission is required to take into account the matters listed in section 2.24 of the Gas Code including:

(a) the service provider's legitimate business interests and investment in the covered pipeline;

(b) firm and binding contractual obligations of the service provider or other persons (or both) already using the covered pipeline;

(c) the operation and technical requirements necessary for the safe and reliable operation of the covered pipeline;

(d) the economically efficient operation of the covered pipeline;

(e) the public interest, including the public interest in having competition in markets (whether or not in Australia);

(f) the interests of users and prospective users;

(g) any other matters that the relevant regulator considers are relevant.

B.2 The process of developing the terms and conditions

In consultation undertaken prior to this review, the Commission expressed the view that the distributors' Access Arrangements should contain a complete set of default contractual provisions. The Commission established a working group (comprising representatives of the distributors, retailers and other interested parties) to review the terms and conditions to apply to reference services from 1 January 2003 with a view to establishing a consistent set of terms and conditions that would be incorporated into the distributors' Access Arrangements.

In the Draft Decision, the Commission noted that distributors had each proposed terms and conditions that were largely consistent.[502] In addition, the distributors indicated that they had based the proposed terms and conditions largely on the electricity default use of system agreement (EUoS), modified to suit the gas industry circumstances and the existing gas Distribution Tariff Agreements (DTA).[503] The distributors noted that such an approach was intended to "facilitate ease of commercial management within the converging energy industry".[504]

As discussed in the Draft Decision and consultation undertaken prior to this review, the Commission expressed the view that it considered it to be in the interests of both distributors and retailers that the distributors' proposed terms and conditions contain standard commercial terms, and are sufficiently complete, clear and unambiguous, and practical and workable. It also expressed the view that, consistent with section 2.24, it would be both efficient and in the interests of distributors and retailers that the proposed terms and conditions be as consistent as possible across the gas industry, and further that it would promote competition in both the electricity and gas markets if there was also some degree of consistency in the terms and conditions applied by distributors and retailers in both of those sectors.

In the Draft Decision, the Commission identified a number of matters associated with the distributors' proposed terms and conditions that it proposed should be amended in order to give effect to issues and comments made by retailers and other interested parties, and where it considered that there were grounds for adopting an alternative approach. However, it also expressed the view that the precise wording to give effect to the Commission's proposed amendments was a matter that would be best progressed by the distributors and retailers continuing to work together. To this end, the Commission indicated that it would reconvene the Terms and Conditions Working Group (comprising retailers, distributors and other interested parties that initiated the proposed terms and conditions) to further discuss the detailed approach to dealing with these matters and work towards developing a standardised and consistent set of terms and conditions across distributors for the Final Decision. To facilitate this process, the Commission indicated that it would prepare a draft revised set of the terms and conditions that could form the basis for further discussion.

Following the release of the Draft Decision, the Commission wrote to each of the distributors, retailers and other interested parties inviting them to form part of the Terms and Conditions Working Group. The distributors subsequently advised that they intended to revise the proposed terms and conditions in light of the Draft Decision and would provide this to the Commission and other interested parties in advance of the Working Group meeting.

---

502 Envestra's proposed terms and conditions for Albury include a number of differences that reflect Albury Gas Company's obligations under relevant NSW legislation.

503 References to the EUoS are based on the EUoS for AGL Electricity Ltd, 23 November 2001.

504 Multinet, Access Arrangement Information, p.10; TXU, Access Arrangement Information, p.6; Envestra, Access Arrangement Information (Victoria), p.59.

In response to the Draft Decision, the Commission received a number of submissions commenting on the amendments required to the terms and conditions as part of the Draft Decision. In addition, the distributors submitted an amended revision to their proposed terms and conditions, which gave effect to a number of the Commission's required amendments.[505]

The Commission convened a meeting of the Terms and Conditions Working Group on 15 August 2002. Following that meeting, the retailers were invited to submit further comments on the amended terms and conditions by 30 August 2002. These comments were provided to the distributors for their consideration. On 5 September 2002, the distributors and the retailers met to discuss further aspects of the terms and conditions.

On 3 September 2002, the Commission received a collaborative submission from the three distributors in relation to the remaining terms and conditions issues. This was followed by a further amended version of the terms and conditions on 6 September 2002 that reflected further agreement reached on a number of the remaining issues of concern to both distributors and retailers. As a result, the number of remaining issues related to the terms and conditions has substantially narrowed since the release of the Draft Decision.

The Commission has based its final assessment of the distributors proposed terms and conditions on this most recent version of the amended terms and conditions as provided on 5 September 2002. As a consequence, the Commission requires amendments to be made with respect to only a few remaining clauses. Nevertheless, this appendix provides an overview of the issues raised in relation to each of the distributors' proposed terms and conditions and the extent to which they have been addressed in the distributors' amended terms and conditions.

B.3 Discussion of proposed terms and conditions

Clause 1 - Definitions and interpretation

Clause 1.1 provides that certain terms are defined with reference to the definitions clause in the distributors' respective Access Arrangement glossaries.

In the Draft Decision, the Commission noted that there were differences in the definitions used by the distributors in their glossaries and proposed that the distributors amend their terms and conditions to:

- include a consistent set of definitions across distributors; and
- provide consistency with the Commission's decision on which services are reference services.

[505] These amended revisions were provided to the Commission on 7 August 2002, and made available on the Commission's website.

It also noted that Multinet's definition of distribution services excludes connection for Tariff D customers, whereas TXU excludes Tariff D and Tariff M connection. In contrast, the 'distribution service' definition included in Envestra's Access Arrangements for Victoria and Albury does not contain any exclusions in relation to connection.

In response to the Draft Decision, the distributors noted that the definitions in the terms and conditions are incorporated by reference to the Principal Arrangements, and they considered it was desirable to retain such a reference to ensure consistency across the Principal Arrangements and the terms and conditions. However, they agreed to accommodate any request from a user for a fully self-contained list of definitions from a user. The Commission did not receive any further submissions from retailers commenting on this issue. Accordingly, it accepts the distributors' argument that it may be desirable to minimise any potential inconsistency that may arise by virtue of having two sets of definitions.

With respect to the approach taken by distributors in relation to the Commission's decision on reference services, the Commission notes that the distributors' Access Arrangement glossaries contain a consistent definition of distribution services. However, the Commission notes that distributors have proposed different approaches to identifying 'services other than reference services'. While the approach taken by Multinet and Envestra (in their Schedules 2 and 3 respectively) to identify such services is consistent with the Commission's decision on reference services, Schedule 3 of TXU's proposed Access Arrangements includes meter installations and testing, disconnection and reconnection services, which it has also listed as ancillary reference services in Schedule 1 of Part A of its Access Arrangements. The Commission therefore requires TXU to amend Schedule 3 of its terms and conditions to remove services that it has identified as ancillary reference services.

As noted in chapter 2, the Commission requires TXU to amend Schedule 3 of its proposed terms and conditions to remove services that it has identified as ancillary reference services.

Clause 2 - Compliance with regulatory instruments

Clause 2 provides for compliance with regulatory instruments and requires precedence to be given to a regulatory instrument over the Agreement in the event of an inconsistency. It also preserves the parties' rights under the Regulatory Instruments and provides for compliance to be waived under certain circumstances.

Specifically, clause 2.4(b) provides that 'a party who has received a written consent described in clause 2.4(a) must provide to the other party a copy of any such consent if that consent is likely to affect the performance of that party's obligations under this Agreement'.

In the Draft Decision, the Commission considered that the clause should be amended to include an obligation for parties to comply with regulatory instruments, and the reference to 'that party' in clause 2.4(b) should also be replaced with 'either party' to ensure both parties have a clear understanding of each other's obligations under the terms and conditions.

At the Working Group meeting of 15 August 2002, the Commission further articulated its view that clause 2 needed to impose an obligation on each party to comply with regulatory instruments.

In response to the Draft Decision and subsequent consultations discussed above, each of the distributors have accepted these proposed amendments and have amended their proposed terms and conditions to make it clear that each party has an obligation to comply with the Regulatory Instruments.

The Commission accepts that this amendment to the proposed terms and conditions addresses the issues raised in relation to this clause.

Clause 3 - Customer relationship

Clause 3 provides that the distributor will supply distribution services to the retailer, except where the retailer notifies the distributor that the customer is not a haulage customer or the distributor and the customer have entered into a haulage agreement directly.

In the Draft Decision, the Commission required each of the distributors to amend clause 3 of their proposed terms and conditions to include a resolution clause to resolve any inconsistencies that may arise from the customer entering into separate supply agreements with both a retailer and a distributor. It also considered that distributors should include a provision precluding the distributor's terms and conditions from operating retrospectively and overriding any pre-existing agreements.[506]

With respect to including a provision for resolving any inconsistencies, each distributor accepted this proposed amendment and amended clause 3(b) of their proposed terms and conditions to provide that:

> If at any time a Customer contracts for the same Distribution Services from both the Distributor and the User, the Distributor and the User will use their reasonable endeavors to implement the contractual relationship desired by the Customer.

The Commission considers that this amendment gives effect to its required amendment on this issue.

However, the Commission remains of the view, having particular regard to clause 2.24(b) of the Gas Code, that the distributors should include a clause preventing the terms and conditions from operating retrospectively.

As noted in chapter 2, the Commission requires each of the distributors to amend clause 3 of their proposed terms and conditions to prevent the terms and conditions from operating retrospectively.

[506] The Commission noted an equivalent clause [3(c)] of the EUoS, stating "Without limiting clause 3(b), this agreement will not apply in respect of a Customer to the extent that and for so long as there is an inconsistent contract between a Customer and the Retailer or the Distributor as at the Commencement Date or between a Customer, the Distributor and the Retailer after the Commencement Date".

Clause 4.1 - Provision of distribution services

Clause 4.1 provides that a distributor will provide distribution services subject to the retailer providing credit support, in accordance with good industry practice and the provisions of the terms and conditions. Pulse Energy and Energex Retail suggested that the clause should include a provision similar to clause 4.1(a)(3) of the EUoS requiring each distributor to provide services to the retailer in accordance with regulatory instruments as if it were providing Distribution Services directly to the Customer.

In the Draft Decision, the Commission proposed that the distributors should amend clause 4.1 to include such a provision.

In response to the Draft Decision, the distributors sought further guidance from the Commission as to how the amendment would promote the interests of retailers or promote competition and the public interest claiming:

> Should a distributor provide distribution services directly to a customer, then the distributor would enter into an agreement with the customer to this effect. The Terms and Conditions Agreement between the distributor and the user would not apply in relation to a customer where there is an agreement between the distributor and that customer to provide distribution services. This is allowed for in clause 3(b) of the draft Terms and Conditions.[507]

Distributors further emphasised this point at the Working Group meeting of 15 August 2002. Retailers have not raised further concerns in response to the distributors' position on this matter.

The Commission accepts the distributors' reasoning that they would enter into a separate agreement with a customer when they provide services directly to a customer. Accordingly, it does not propose to require the distributors to further amend clause 4.1.

Clause 4.4 - Entitlement to refuse service

Under clause 4.4, a distributor is not required to supply distribution services where it is not required or permitted to supply pursuant to a regulatory instrument, the gas does not meet the required specifications or the distributor reasonably believes the quality of the gas to be deleterious, or the retailer has not made payment within 7 days of a default notice.

In response to the proposed terms and conditions, a number of retailers expressed concern with clause 4.4(c), noting that a distributor should not be entitled to refuse supply for non-payment unless the dispute resolution clauses set out in clause 14 have been followed. In the Draft Decision, the Commission required each of the distributors to amend clause 4.4(c) to clarify that it does not apply where the retailer has notified a dispute under clause 14.2.

507 Multinet, Response to Draft Decision, p.16; TXU, Response to Draft Decision, p.27; Envestra, Response to Terms and Conditions Amendments, 9 August 2002, p.3.

In response to the Draft Decision, each of the distributors have accepted this proposed amendment and have amended clause 4.4(c) of their proposed terms and conditions to clarify that it does not apply where the retailer has notified a dispute under clause 14.2.

Accordingly, the Commission does not require any further amendment to this clause.

Clause 4.6 - Conditions of supply

Clause 4.6(f) provides that the quality of gas delivered at the supply point might not match the quality injected into the system by the user. In response to the proposed terms and conditions, TXU Retail suggested that the distributor should have some obligation in relation to the quality of gas provided.

In the Draft Decision, the Commission noted that the distributor is unlikely to be in any better a position than the retailers to adversely affect or protect quality and did not require any amendment of this clause. The distributors subsequently advised that the relevant clause 4.6(f) is the same as clause 10.1(h) of the current Version 7 of the Gas Distribution System Code.

That is, retailers are required to accept that any gas injected in to the system will be co-mingled and accordingly, the distributor is not able to ensure that the gas leaving the system is of the same quality as that injected. As a result, the Commission remains of the view that clause 4.6 appears to be reasonable and does not require amendment.

Clause 4.7 - The user’s obligations/capacity management

Under clause 4.7, unless otherwise agreed in advance, the retailer is required to:

- not deliver gas greater than the transfer point’s capabilities;
- pay for any damage to the distribution system where it is the result of the retailers’ failure to not deliver gas greater than the transfer point’s capabilities;
- ensure that gas injected complies with the relevant specifications; and
- except where permitted, ensure a customer does not withdraw gas in excess of its MHQ.

In the Draft Decision, the Commission noted that the clause appears to relate to the retailer’s ability to control flows into and out of the distribution system. On this point, retailers argued that they have limited control over ensuring the quality of the gas transmitted into the distribution system. The Commission accepted this argument and noted that distributors might be in a better position than retailers to minimise the chance of incidents associated with gas entering the system. Accordingly, it required each of the distributors to revise clause 4.7(a), (b) and (c) to reflect the practical limits on a retailer’s ability to control the volume and specification of gas delivered and injected into the distribution system.

In response to the Draft Decision, the distributors agreed to amend clause 4.7(a) to qualify that users are required to ensure that the volume or pressure of gas delivered to a transfer point does not exceed the physical designs of the system *'to the extent that such matters are within the User's reasonable control'*. The distributors argued that clause 4.7(b) refers to clause 4.7(a), and as such does not require amendment. The distributors did not agree with the Commission's proposed amendment to clause 4.7(c), arguing that conformance of gas to specification is a contractual matter between the retailers and the producers and transmission companies.

AGL rejected the distributors' claims that retailers' obligations under 4.7(c) should not be qualified, arguing:

> We understand that the equivalent DTA provisions (clause 5.3(c)) has not caused problems for DBs to date and there seems to be no grounds for qualifying the retailers obligations with respect to volume and pressure (in clause 4.7(a)) but not qualifying retailers obligations with respect to gas specifications (in clause 4.7(c)).[508]

However, the distributors maintained that the retailer is best placed to manage the conformance of gas to specifications through its contacts with producers and transmission companies, with Envestra claiming:

> The proposed amendment suggests that a retailer can approach a distributor to seek injection and haulage of gas, but give no guarantee as to the physical condition and content of the gas it seeks to inject. It is not possible for a distributor to agree to provide a reference service when such basic parameters cannot be guaranteed. Distributors fail to see how a retailer can absolve itself of such responsibilities. It is the retailer that contracts with upstream parties for the supply of gas to the distribution system, and it is the responsibility of the retailer to ensure that the respective parties in turn deliver gas at the correct specification. Distributors are not in a position to do this and cannot be expected to.[509]

The distributors also referred to Access Arrangements approved in a number of other jurisdictions that require retailers to be responsible for the quality of gas entering the network, including in relation to AGL's NSW network, Envestra's Mildura network and Envestra's Queensland network.[510] On balance, the Commission agrees with the distributors' position that the retailer – and not the distributor – is the appropriate party to manage conformance of gas with specifications.

The Commission considers that the distributors proposed amendment to clause 4.7(a) appropriately gives effect to the Commission's required amendment, and accepts that amendment to clause 4.7(b) is not required on the basis that it refers to clause 4.7(a).

Accordingly, it does not require any further amendment to this clause.

---

508 AGL, Comments on ReDrafted Terms and Conditions, 23 August 2002, p.2.

509 Envestra, Response to Terms and Conditions, 9 August 2002, p.4.

510 Multinet, Response to Terms and Conditions Working Group Meeting (15 August 2002), 3 September 2002, p.4; TXU, Further Response to Draft Decision and to further submissions from gas retail businesses and users, 3 September 2002, p.4; Envestra, Further submission in response to ESC requested amendments and submission in response to various gas retail business submissions, p.4. [Hereon, these submissions will be collectively refered to as 'Distributors' further responses to terms and conditions; page number refers to the Envestra submission].

Clause 4.8 - Title to gas

Clause 4.8 provides that, at all times, the retailer has title to injected gas and that the gas will be free of any lien, encumbrance or other charge. Pulse Energy, TXU Retail and Energex Retail considered it inappropriate for users to warrant that gas is free of any encumbrance on the basis that it might be important for small retailers to be permitted to grant financiers a charge against the gas, as gas may be one of retailers' few tangible assets.

In the Draft Decision, the Commission accepted the retailer's concerns that the clause was not in the interests of users or prospective users and likely to reduce the benefits of competition and required that the clause 8.4(b) dealing with title to gas be deleted.

In response, the distributors proposed to delete the warranty contained in clause 4.8(b) that required all gas to be free of any lien, charge encumbrance or adverse claim. However, they also expressed the view that they should not take any risk arising from the title to gas, and accordingly have applied the indemnity to the retailer's warranty in relation to title contained in clause 4.8(a).[511] No further comments were received from retailers on this amended clause.

The Commission accepts distributors' amendment to clause 4.8.

Clause 4.10 - Unaccounted for gas (UAFG)

As noted in Chapter 2, clause 4.10 of the proposed terms and conditions sets out a process for annually reconciling and settling payments between distributors and retailers to reflect performance against UAFG benchmarks. It also deals with a number of other related payment terms.

In the Draft Decision, the Commission considered it appropriate that the basis for calculation of UAFG be transparent and proposed to amend the Gas Distribution System Code to revise the existing UAFG benchmarks and set out the methodology to be used by VENCorp to calculate the UAFG reconciliation payments.

Accordingly, the Draft Decision proposed that each of the distributors amend clauses 4.10(b) and (c) of their proposed terms and conditions to note that the UAFG reconciliation amounts must be calculated according to the methodology prescribed in the Gas Distribution System Code.

In response, the distributors have amended clause 4.10(b) to note that the UAFG reconciliation amounts must be calculated according to the methodology prescribed in the Gas Distribution System Code. However, they argued that clause 4.10(c), which deals with payment terms for the Reconciliation Amount, does not require amendment.[512] The Commission accepts this position.

[511] Multinet, p.18; TXU, p.28; Envestra, p.5.
[512] ibid.

The distributors also inserted additional words into clause 4.10 that state that *'the user accepts risk of loss of all Gas injected by it into the Distribution system...'*. While AGL sought to have these additional words deleted, the Commission accepts the distributors' reasoning that these words are equivalent to clause 10.1(d) of the current Gas Distribution System Code Version 7.[513]

The Commission accepts distributors' amendments to clause 4.10.

Clause 5 - Connection

Clause 5 requires a user to provide the distributor with certain information to facilitate the connection of a new customer. In response to the proposed terms and conditions, Energex Retail submitted that a retailer's obligations in respect of connection should be in accordance with the regulatory instruments. TXU Retail submitted that clause 5 should include the distributor's obligations in respect of connection, and allow retailers to recover the costs of facilitating the connection. TXU Retail reiterated this claim in response to the Draft Decision.

In the Draft Decision, the Commission noted that distributor obligations in relation to connections are already set out in clause 3 of the Distribution System Code. In response to the Draft Decision, the distributors submitted that the obligation on the parties under clause 2.2 of the terms and conditions to comply with any regulatory instrument should be adequate to enforce the relevant requirement of the Gas Distribution System Code.[514] With respect to retailer costs of facilitating new connections, the Commission considers these to be standard costs incurred by a retailer in doing business, rather than costs incurred on behalf of a distributor.

The Commission considers clause 5, which relates to retailer obligations with respect to connections, to be reasonable.

Clause 6.1 - Disconnection and curtailment

Clause 6.1 provides that (pursuant to clause 6.1(a)), a retailer acknowledges the distributor's right to disconnect, curtail or interrupt supply in an emergency or otherwise in accordance with the Gas Distribution System Code and any other applicable regulatory instruments. Clause 6.1(b) provides distributors with the discretion to choose which supply points to curtail.

In the Draft Decision, the Commission noted Origin Energy's concerns that involving distributors in the disconnection process will introduce inefficiencies and delays, and that retailer should continue to handle disconnections in accordance with current practice. TXU Retail also suggested that the distributor should be required to consult with the retailer in making a decision to disconnect, curtail or interrupt supply under this clause, except in an emergency. Further, Energex Retail considered it unnecessary for clause 6.1(b) to expressly permit distributors to exercise these rights as they are already provided for in the regulatory instruments.

---

513 AGL, Response to Draft Decision, 7 August 2002, p.8.
514 Distributors' further response to Draft Decision, p.6.

In the Draft Decision, the Commission required each distributor to amend clause 6.1 of its proposed terms and conditions to allow retailers to disconnect a customer for non-payment in accordance with the Gas Distribution System Code or any other applicable regulatory instrument. It also required a provision to be inserted to require distributors to consult with retailers about the order in which customers are to be interrupted.

In response, the distributors have amended clause 6.1 of the draft terms and conditions to allow that where practicable, the retailer will be notified as to which distribution supply point will be curtailed, interrupted or disconnected. However, they did not consider that it is practicable to notify or consult with retailers in all circumstances, particularly in cases of emergency, and noted that retailers were involved in the development of VENCorp's Gas Load Emergency Curtailment Rules.[515]

In relation to allowing the retailers to disconnect customers, the distributors expressed concerns about:

> … public safety issues, liability and damage to their equipment caused by or due to untrained or accredited contractors of the retailer disconnecting supply. Customers disconnected for non-payment of debt will also be able to transfer to another retailer. Therefore, distributors must have control of how/who disconnects supply as they have the regulatory obligation to reconnect (situations may arise where retailers use their own locks and therefore the distributor would be hindered in restoring supply).[516]

The distributors also noted that clause 6.2 permits the retailer to request that the distributor disconnect a customer's distribution supply point.[517]

The Commission, in having particular regard to section 2.24(c) of the Gas Code, accepts the distributors' amendment to clause 6.1.

Clause 6.2 - Disconnection at the request of the user

Clause 6.2 deals with rights and obligations where a retailer requests that a customer be disconnected. The proposed clause is subject to both the regulatory instruments and to clause 6.2 of the proposed terms and conditions, and retains the distributors' discretions to not perform a disconnection.

In the Draft Decision, the Commission considered it appropriate to include a clause to provide distributors with an incentive to perform disconnections within prescribed timeframes. It also required each distributor to amend clause 6.2 to include a provision requiring distributors to waive the network tariff and indemnify the retailer against network and energy costs where it fails to disconnect on time.

---

515 Multinet, p.19; TXU, p.29; Envestra, p.6.
516 Envestra, Response to Terms and Conditions Amendments, 9 August 2002, p.6.
517 ibid.

In response to the Draft Decision, each of the distributors has accepted this proposed amendment and has amended clause 6.2 of their proposed terms and conditions to waive charges and meet the gas consumption costs incurred by a retailer due to delays in effecting a disconnection where they have failed to disconnect on time, or have not made a reasonable attempt to do so. In doing so, distributors contended that 'their operations in relation to disconnection are both efficient and timely but that this new clause reinforces the incentives for distributors to be so'.[518]

TXU Retail objected to clause 6.2(d)(3), under which distributors retain discretion to not disconnect a customer for non-payment of debt.[519] However, the Commission considers that this clause is appropriate, on the general principle that customers should not be disconnected where outstanding amounts have been paid.

The Commission accepts the distributors' proposed amendments to clause 6.

Clause 6.4 - Reconnection or restoration of supply

Clause 6.4 deals with the distributors' and retailers' rights and obligations in relation to reconnection or restoration of supply. The clause is based on clause 6.5 of the EUoS, but it gives a gas distributor additional discretion to refuse to reconnect or restore supply where it considers it unsafe to do so. The retailers submitted that all disconnections should be in accordance with the regulatory instruments and the additional discretion should be removed.

In the Draft Decision, the Commission required each of the distributors to amend clause 6.4(b) of its proposed terms and conditions to limit the distributors' discretion over reconnection and restoration to that contemplated by the regulatory instruments, and to require that all disconnections are undertaken in accordance with the regulatory instruments.

The distributors did not consider that amending clause 6.4(b) to limit their discretion over reconnection was justified on the basis that:

> The proposed amendment has the effect of requiring a distributor to take into account only the requirements of Regulatory Instruments. Distributors regard safety as paramount and regardless of whether the Regulatory Instruments allow the distribution supply point to be reconnected, the distributors fail to understand why any party would wish gas to be connected to a property where it is unsafe to do so.
>
> The Distribution System Code at clause 4.2 states that a distributor 'must' reconnect a customer once the reason for disconnection ceases or expires. This means that a distributor must reconnect a customer even where it is unsafe to do so. Contrary to the Commission's view that this is "not in the interests of retailers or prospective users" the distributors firmly believe the existing clause to be in the interest of all relevant parties, including the public and in particular the customer.[520]

518 Distributors' further response to Draft Decision, 3 September 2002, p.7.
519 TXU Retail, 26 August 2002, p.2
520 Multinet, p.7; TXU, p.30; Envestra, p.7.

The distributors also submitted that the refusal to reconnect a customer would only be taken with due consideration, and noted that the proposed terms and conditions emphasise that they will not refuse to reconnect a customer without first forming the opinion that it is unsafe to do. In doing so, the distributors argued that the clause was consistent with ensuring the 'operational and technical requirements for the safe and reliable operation of the Covered Pipeline.' The distributors also argued that the Gas Distribution System Code does not specifically refer to safety issues, with the proposed clause emphasising this safety aspect.

The Commission, having particular regard to section 2.24(c) of the Gas Code, accepts this position.

Clause 7.1 - Charges

Clause 7.1 establishes obligations and procedures relating to charges paid by a retailer to the distributor. In the Draft Decision, the Commission required each of the distributors to amend the relevant clauses of their terms and conditions to adopt the existing gas industry practice of basing distribution charges on physical metering data.

AGL supported this proposed amendment, adding:

> We assume that the amendment will involve the inclusion of a clause in terms corresponding with EUoS clause 7.4(d). This EUoS clause provides (in part) that the network tariff component must only include network tariff charges "for Customers whose meters were due to be read in the period of the invoice … or in relation to the correction or substitution of previous meter reads relating to earlier invoicing periods. All other services will be invoiced after the provision of the Service unless otherwise agreed by the parties or required by the Electricity Law.[521]

The distributors agreed to amend clause 7.4 to include a new 7.4(f), which allows for charges to be based on metering data. The Commission considers that this amendment gives effect to the Commission's required amendments.

Clause 7.2 - Retail service charges

In the Draft Decision, the Commission noted Pulse Energy's comments that clause 7.2 relating to retail services charges raises retailer obligations under clause 8.2(b), which require the retailer to provide a privacy notice on behalf of the distributor. Pulse Energy's comments appear to suggest that the retailers' obligation under 8.2(b) to provide privacy notices to a customer on behalf of a distributor should be a Retail Service under clause 7.2 for which the distributors should be required to pay fair and reasonable fees. This matter is discussed under the clause 8.2 below.

Clause 7.4 - Distribution services – invoicing, payment and interest

Clause 7.4 establishes procedures and obligations relating to invoicing and payment for distribution services provided by the distributor to the retailer.

[521] AGL, Response to Draft Decision, 7 August 2002, p.8.

In the Draft Decision, the Commission noted the comments expressed by Energex Retail that this clause should be amended to require each party to use reasonable endeavours to issue invoices on the same business day of each month and to provide for payments to be made within 10 business days rather than 10 days [clause 7.4(i)]. Origin Energy sought conformity between the terms and conditions and the EUoS, and requested a 15-day period for payment.

In the Draft Decision, the Commission considered that there would be merit in aligning payment terms for gas with those for electricity on the basis that it would facilitate greater efficiency and competition in the retail electricity and gas markets. As a result, it required the distributors to amend clause 7.4 to provide for invoicing and payment terms (along the lines of clauses 7.4 and 7.8 of the EUoS).

The distributors did not consider that the proposed amendment was appropriate given that the current Distribution Tariff Agreements reflect current gas industry practice of issuing a mid-month and a monthly invoice.[522] They also claimed that removing the distributors' ability to invoice on a mid-month and end-month basis would have significant negative cash flow implications for the distributors, and that they would need to seek a working capital allowance if the Commission insisted upon such an invoice payment regime.

Nevertheless, the distributors amended their proposed terms and conditions to provide that distributors would use best endeavours to invoice on the same business day each month, mid-month invoices will be calculated using actual metering data, and allowing retailers 10 days to pay invoices, regardless of whether it is mid-month or end-month.

In responding to the distributors comments and amended terms and conditions, TXU Retail continued to seek to alignment with the EUoS, by allowing retailers 10 *business* days to pay or dispute any invoices.[523] Origin Energy also argued that 10 business days would avoid inefficiencies that may arise over holiday periods.[524]

The Commission considers that it is reasonable to require the terms and conditions to allow retailers to pay or dispute their invoices within 10 business days rather than 10 days.

On the issue of monthly invoicing, the Commission sought further information from retailers about the cash flow implications, if any, which would arise from a change to monthly invoicing. Energex Retail submitted that it would achieve savings, but did not quantify the magnitude of any savings.[525]

The distributors disputed that retailers would incur any material additional costs as a result of mid-monthly billing and submitted that the current practice of mid-monthly billing was working effectively.[526] Further, they argued that if monthly billing were introduced, distributors would be likely to incur significant additional IT costs as a result of the need to expand IT system capacity to handle additional data.

522 Multinet, p.33; TXU, p.31; Envestra, p.8.
523 TXU Retail, Submission, 26 August 2002, p.2.
524 Origin Energy, Submission, 23 August 2002, p.1.
525 Email from D. Vigilante (Energex) to A. Chow (ESC), 26 August 2002.
526 Distributors' further response to Draft Decision, p.8.

The Commission notes the current arrangements for mid-monthly billing and the distributors' arguments that monthly billing would impose additional costs. In the absence of further information from the retailers that a change to mid-monthly billing arrangements would result in savings to consumers, the Commission accepts that further amendment to the clause to give effect to the billing cycle is not required.

However, it remains of the view that the distributors should be required to amend clause 7.4(i) to permit users to pay invoices received within 10 *business* days after the day on which the invoice is received.

As noted in chapter 2, the Commission requires each of the distributors to amend clause 7.4(i) of their proposed terms and conditions to permit users to pay invoices within 10 *business* days after the day on which an invoice is received.

Clause 7.5 - Adjustment of invoices

Clause 7.5 requires an incorrect charge in an invoice to be altered to correct an error and is based on Clause 7.6 of the EUoS. Clause 7.5(c) in the proposed terms and conditions provides for an exception to non-adjustment in respect of defective meter readings, errors in billing of gas consumption and differences in the actual and estimated readings, obtained after the invoice is issued, where a retailer is precluded by the regulatory instruments from recovering from its customer, except where the incorrect charge arises as a result of an act or omission of the retailer or a customer.

In the Draft Decision, the Commission noted Pulse Energy's comments that clause 7.5(c) should provide that an adjustment should not be permitted if it is the result of an error by VENCorp in providing data to the distributor, as is provided for in clause 7.5(a)(3). In response to the Draft Decision, AGL reiterated this point, claiming that it is appropriate for clause 7.5(a)(3) to include an error by VENCorp, as a matter that is outside the retailer's control.[527]

Clause 7.5(c) in the proposed terms and conditions provides for an exception to adjustments in respect of defective meter readings, errors in billing of gas consumption and differences in the actual and estimated readings, obtained after the invoice is issued, where a retailer is precluded by the regulatory instruments from recovering from its customer, except where the incorrect charge arises as a result of an act or omission of the retailer. In the Commission's view, having regard to sections 2.24(a) and 2.24(f) of the Gas Code, it would be appropriate for clause 7.5(c) to explicitly exclude the application of 7.5(a)(3) (errors by VENCorp in its provision of data to the Service Provider).

As noted in chapter 2, the Commission requires each of the distributors to amend clause 7.5(c) of their proposed terms and conditions to explicitly exclude the application of 7.5(a)(3).

527 AGL, Response to Draft Decision, 7 August, 2002, p..9.

Clause 7.6 - GSL payments

Clause 7.6 of Multinet and TXU's proposed terms and conditions set out the distributors' and retailers' rights and obligations in relation to GSL payments as well as a Schedule defining the proposed GSL events (ie. definitions, payments conditions and amounts).[528]

In the Draft Decision, the Commission expressed the view that the GSLs represented a service level commitment to end-use customers rather than retailers, and as such the GSL events would be most appropriately included in the Gas Distribution System Code. As a result, the Commission required both Multinet and TXU to amend clause 7.6 of their proposed terms and conditions to:

- refer, and give effect, to the GSL scheme that is to be outlined in the Gas Distribution System Code;
- delete the Schedules defining the proposed GSL events (which will be defined in the Gas Distribution System Code); and
- require the distributor to notify the retailer where it has made a GSL payment directly to a customer.

In addition, it required Envestra to insert a new clause into its terms and conditions to give effect to the GSL scheme, as proposed by Multinet and TXU and amended by the Draft Decision.

In response, the distributors - including Envestra - agreed to amend their proposed terms and conditions to give effect to the Commission's required amendments.

The Commission has noted that the Gas Distribution System Code does not currently apply in respect of Envestra's Albury network (by virtue of the fact that it is also regulated under NSW legislation).[529] As a result, the Commission proposed that, in the absence of superior available arrangements at this time, Envestra should include a provision in its terms and conditions for Albury defining the GSL events and payments as set out in the Final Decision (see section 2.6). The Commission also proposed that Envestra insert a clause in its terms and conditions for Albury, providing for the clause to cease to have effect in the event that a similar provision in the Gas Distribution System Code purports to give effect to the GSL scheme in relation to Envestra's Albury network.

As noted in chapter 2, the Commission requires Envestra to amend it proposed terms and conditions to:

- define the GSL events and payments applicable to the Albury network as set out in the Final Decision; and
- provide for the clause to cease to have effect in the event that a similar provision in the Gas Distribution System Code purports to give effect to the GSL scheme in relation to Envestra's Albury network.

---

528 Envestra did not include such a provision on the basis that it did not propose to introduce a GSL scheme for its Victorian and Albury customers.

529 This issue is discussed in section 2.6 of the Final Decision.

Clause 7.7 - Disputed invoices

Clause 7.7 sets out procedures for the user and distributor to follow regarding a disputed invoice. In the Draft Decision, the Commission noted a number of issues raised by retailers in relation to this proposed clause, including in relation to payments to be made to the distributor in the event of a disputed invoice. For example, TXU Retail argued that clause 7.9(c)(2) of the EUoS, on which clause 7.7(c)(2) is based, is not working practically and as a result the proposed clause in the gas distributors' terms and conditions should be deleted. In the Draft Decision, the Commission sought further comments on the operation of the equivalent clause in the EUoS.

Further submissions from TXU Retail and Origin Energy stated that the clause should be amended to provide that the retailer should only be required to pay an amount reasonably argued by the parties, or the undisputed part of an invoice and not 80 per cent of the amount of the previously undisputed invoice as proposed in clause 7.7(c)(2).[530] In particular, Origin Energy argued that there were practical difficulties associated with administering this clause and issues with seasonal variation in invoices, whereby 80 per cent of the previously undisputed invoice may be greater than the entire amount in dispute. In contrast, the distributors argued that there had not been any problems to date with the regime.

The Commission notes the practical difficulties raised by Origin Energy associated with administering this clause. As a result, it considers that the distributors should be required to delete clause 7.7(c)(2) and require that only the amount of the invoice that is not in dispute should be paid. The Commission also notes that clause 7.7(e) provides for the recovery of overpaid (or underpaid) amounts, plus any interest accruing, following resolution of the dispute. As a result, the Commission considers that this should be sufficient to protect the commercial interests of either party and to provide an incentive for any disputed payments to be resolved expeditiously.

As noted in chapter 2, the Commission requires each of the distributors to delete clause 7.7(c)(2) of their proposed terms and conditions.

Clause 7.8 - Credit support

Clause 7.8 of the proposed terms and conditions provides that the distributor may require the retailer to provide a bank guarantee to secure payment of charges (with the size of the guarantee not exceeding 3 months of average charges). It also sets out the procedures for increasing or decreasing the amount of the guarantee.

---

530 TXU Retail, Submission, 26 August 2002, p.2; Origin Energy, Submission, 24 July 2002, p.3.

A number of retailers argued that clause 7.8 should be amended to reflect the credit support arrangements in clause 7.10 of the EUoS, which provides for a distributor to require a bank guarantee from a retailer only in certain circumstances. In the Draft Decision, the Commission accepted the principle implied in the distributors' proposed credit support arrangements that the distributors should be substantially shielded from the risk of retailer default. However, it considered that the proposed credit support arrangements would impose significantly greater costs on the retailers than alternative arrangements, with no material change in the level of risk borne by the distributors. As a result, it considered that the proposed arrangements were not in the interests of users or prospective users and were adverse to the public interest associated with having competitive markets, while providing no material impact on the distributors' legitimate business interests. As a result, it required each of the distributors to amend clause 7.8 to define the circumstances under which a distributor may request a retailer to provide credit support.

In response, the distributors submitted initially that the credit support provisions set out in the EUoS are less favorable than the proposed terms and conditions:

> The distributors' current experience is that a distributor's right to seek a bank guarantee has been an effective tool in managing credit risk and ensuring that retailers comply with contractual payment terms. Distributors have been responsible in the exercise of their rights and current commercial arrangements have worked well to-date. While the EUoS arrangements provide for less discretion on the part of the distributor, the distributors are of the view that, given the recent events surrounding Enron and Worldcom, such discretion is prudent and reasonable.[531]

The distributors subsequently met with TXU Retail, AGL, Origin Energy, Energex Retail and Energy Advice to discuss the issue further. In a further submission, Envestra subsequently advised that all users at the meeting had the same concerns that clause 7.8 of the proposed terms and conditions, as currently drafted, lacked objectivity "in respect of what was a suitable credit rating" and in "the absence of credit support triggers".[532] Further, Envestra indicated that there was agreement amongst all parties that clause 7.10(a) of the EUoS would overcome these issues, provided that specific alternatives to the Standard and Poor's BBB- credit rating were also made available. The distributors and the users accepted as alternatives a Moody's credit rating of Baa3, or a Fitch credit rating of BBB-. The Commission agrees that these ratings provide reasonable alternatives to the Standard and Poor's BBB- rating.

The distributors advised the Commission that the users and the distributors have agreed to adopt a revised version of 7.10(a) of the EUoS to align the credit support triggers to the bi-monthly billing terms included in the proposed terms and conditions. The Commission accepts distributors' amendments to clause 7.8.

---

531 Multinet, p.24; TXU, p.32; Envestra, p.10.

532 Envestra, Final Submission on Terms and Conditions, 6 September 2002, p.2.

Clause 8 - Information exchange

Clause 8.2(b) requires the retailer to provide the customer any privacy notices that may be required under privacy laws and the regulatory instruments. Energex Retail argued that clause 8.2(b) is unworkable and should be deleted. However, it also suggested that if it were retained, the clause should be amended to allow the retailer to charge for providing this service. Energex Retail also proposed that clause 8.4, under which the parties acknowledge that the Gas Interface Protocol may apply to notices or communications issued under the terms and conditions, should be deleted as the obligations under the Gas Interface Protocol are defined elsewhere.

In the Draft Decision, the Commission expressed the view that in light of the privacy laws, clause 8.2(b) appears to be appropriate, and that clause 8.4 also appears to be appropriate.

In response to the Draft Decision, AGL sought clarification as to what the privacy notices will address.[533] The Commission considers that the purpose of the privacy notices is to discharge the obligations of the service provider under privacy laws and regulatory instruments in respect of customer information disclosed by the retailer to the distributor.

The Commission remains of the view that clause 8 is appropriate and does not require an amendment to this clause.

Clause 9 - Communications regarding customers and systems data

Clause 9.4 relates to customer information that the distributor requires from retailers. The proposed clause requires the retailer to provide to the distributor, on a monthly basis, information for each customer, including the customer's name, contact details, telephone number, site address and metering installation registration number (MIRN).

In response to the proposed terms and conditions, Pulse Energy called for further consultation about clause 9 to clarify the circumstances in which the distributor can request the information specified in the clause. In response to the Draft Decision, AGL submitted that:

> AGL is also of the view that faults and interruptions are not nearly as frequent in gas as they are in electricity; we do not believe that there is a good case for service providers being provided with customer name details on a regular basis. In the case of a 'supplier of last resort' event, there can be a separate requirement for retailers to provide customer details where requested by the Commission for this purpose. In relation to any ad hoc requirements by the distributor to contact customers, retailers can provide names on a case-by-case basis.
>
> We are of the view that there should be no obligation to provide customer information to distributors on an ongoing basis (contrary to EUoS clause 9.4(b)). However, if such an obligation is imposed on retailers, the retailer should be entitled to a fair and

533 AGL, Response to Draft Decision, 7 August 2002, p.9.

> reasonable fee to recover costs incurred in providing the information or have its retail tariffs adjusted to reflect this additional obligation.[534]

In response, the distributors argued that while faults and interruptions are not as frequent in gas as in electricity, there are a number of reasons why the provision of the customer information should be made available:

(a) to support the retailer safety case;

(b) to ensure the distributor has an ability to identify the parties to the Deemed Contract, which will be put in place between a distributor and a customer;

(c) Retailer of Last Resort purposes;

(d) To ensure the distributor has an ability to provide improved customer service.[535]

Further, the distributors' commented that any cost of providing such information should rest with the retailer who can pass on the cost to customers. They also advised that they had prepared their 2003-07 forecasts on the basis of this position and the Commission would need to adjust their revenue benchmarks if this were to change. The Commission considers that the requirement for retailers to provide customer information to distributors is appropriate in the context of the distributors' service obligations, and accepts the distributors' reasons for requiring contact and address details for customers, in order for them to be able to respond promptly to emergencies and to facilitate customer service. The Commission notes that it did not receive any submissions estimating the costs of maintaining the customer databases, but is of the view that it is unlikely to be onerous on retailers.

The Commission considers clause 9.4 of distributors' proposed terms and conditions to be reasonable, having regard to section 2.24(c) of the Gas Code.

Clause 9.1 - Answering fault and emergency calls

Clause 9.1 requires the retailer to transfer customer telephone calls concerning gas leaks and emergencies to the distributors' gas leaks and emergencies telephone number, and to publish the supply and appliance faults numbers on accounts, in accordance with the Gas Leaks and Emergencies Calls Protocol.

In response to the proposed terms and conditions, TXU Retail expressed concern about the transition from the existing procedures for emergency calls to the procedures specified in clause 9.1. It also advised that, while it understood that distributors would not be in a position to comply with clause 9.1 until 1 January 2003, the transition to the new billing system for FRC occurs on 15 September 2002. Whilst it did not require an amendment to this clause, it sought clarification of the transition procedures that are to apply.

In the Draft Decision, the Commission noted that clause 9.1 would not apply prior to 1 January 2003. The transition procedures for notification of faults and emergencies are being addressed as part of a separate process.

---

534 Ibid.

535 Distributors' further response to Draft Decision, p.10.

Clause 9.5 - New distribution supply points

Clause 9.5 specifies the nature of information that a retailer is required to provide a distributor for each new distribution supply point that the retailer wishes to be connected. In response to the proposed terms and conditions, TXU Retail argued that retailers are not able to provide the details required by clauses 9.4 and 9.5. In a further submission, TXU Retail advised that the retailer may not be able to provide all the required details (for example, retailers may not have access to a MIRN for a new customer).

The Commission notes that clause 9.5 only requires the retailer to provide the MIRN for a new connection, 'if known'. As a result, it does not consider that it is necessary to amend the clause further.

Clause 9.9 Ombudsman complaints

Clause 9.9 refers to the process by which parties to the terms and conditions will handle complaints referred by the Energy and Water Ombudsman (EWOV). In response to the proposed terms and conditions, TXU Retail submitted that this clause may need to be amended following the conclusion of the Ombudsman's review of its case handling policy to ensure consistency. The Commission has received advice from EWOV that the clause is consistent and workable in relation to its complaints handling policy. As a result, it does not consider that any amendment to the clause is required.

Clause 9.10 - Assignment of and changes to reference tariffs

Clause 9.10 sets out the distributors' obligations to notify retailers of changes to reference tariffs. In response to the Draft Decision, AGL raised concerns that they may not receive adequate notice of amendments to reference tariffs to update their systems and provide notice to customers.[536]

The Commission notes that in this Final Decision, the Commission has required distributors to submit new reference tariffs to the Commission at least 60 days prior to the commencement of the next calendar year. In the interests of promoting transparency, the Commission proposes to make these new reference tariff schedules available publicly on its website. Accordingly, it considers that this should provide retailers with adequate notice of any proposed changes to reference tariffs.

Clause 9.12 - Information for customers

Clause 9.12 sets out the procedures for dealing with customers' requests for documentation or information, including the circumstances where the retailer is permitted to provide information on behalf of the distributor.

---

536 AGL, Submission, 23 August 2002, p.3.

In response to the proposed terms and conditions, the retailers submitted that they should be able to charge the distributor for providing the Distribution System Code and other standard information or documents on its behalf. In the Draft Decision, the Commission expressed the view that there was no reason why this clause should differ from arrangements for electricity which provide for the distributor to pay the retailer a 'reasonable fee' in certain circumstances (clause 9.10(f) of the EuoS), and required the distributors to incorporate clause 9.12(a) of their proposed terms and conditions (relating to the provision of information to customers) in the definition of a Retail Service[537].

In response to the Draft Decision, the distributors indicated that the definition of retail services in the terms and conditions already includes the provision of information and documentation to customers under clause 9.12(b) and delivering to a customer any notification, information or documents as requested by a service provider under clause 9.12(e).[538] Accordingly, the distributors submitted that no amendment is necessary.

The Commission accepts that this provision adequately addresses this issue, and as a result it does not require any further amendment.

Clause 10 - Force majeure

Clause 10 suspends a party's obligations where force majeure occurs, with force majeure having the same meaning as in the Gas Distribution System Code. Parties are required to use all reasonable efforts to mitigate the effect of a force majeure event, and give notice when it arises or is likely to arise.

Energy Advice noted that the distributors' proposed terms and conditions do not provide for a customer to be given early warning of a force majeure event, which would potentially enable the end user to more rapidly take steps to mitigate against any adverse effects caused by the event.

In the Draft Decision, the Commission noted that this clause is based on clause 10 of the EUoS, and also noted that the proposed terms and conditions do not prohibit a retailer from notifying a customer of a force majeure event. However, it considered that it was appropriate to expressly allow such a disclosure, and proposed that clause 10 be amended to allow retailers to notify customers of a force majeure event.

In response, the distributors agreed that the terms and conditions do not prohibit a retailer from notifying a customer of a force majeure event, but noted that the terms and conditions are not intended to govern all facets of communication between retailers and customers.[539] On that basis, distributors argued that it is unnecessary to amend the terms and conditions to expressly provide for such notification when it is unrelated to the commercial ambit of the terms and conditions between a retailer and a distributor.

---

537 Under 7.2(a) of distributors' proposed terms and conditions, the distributors shall pay a reasonable fee to a retailer where it requests a retailer to provide a retail service.

538 Multinet, p.25; TXU, p.33; Envestra, p.10.

539 Multinet, p.26; TXU, p.33; Envestra, p.11.

The Commission accepts that this may be a matter best dealt with in a regulatory instrument other than the terms and conditions for use of the gas distribution system. As a result, it does not propose to require any further amendment.

Clause 11 - Enforcement of distributors' rights against customers

Clause 11 sets out the circumstances whereby distributor can directly enforce their rights to disconnect a customer, without first notifying or consulting with the retailer.

In the Draft Decision, the Commission expressed the view that this clause should expressly preserve the supremacy of the Gas Law. It also supported Energex Retail and Pulse Energy's recommendations that the proposed terms and conditions should include a schedule listing customers' obligations that if breached or likely to be breached by a customer, the retailer is required to give the distributor notice of under clause 11.4. Finally, the Commission agreed that a retailer's failure to provide notification should not be grounds for termination.

In the Draft Decision, the Commission required each of the distributors to amend its proposed terms and conditions to:

- make the parties' obligations under the clause subject to their obligations under the regulatory instruments (clause 11.2(a));
- include and refer to a schedule that includes a list of the matters in respect of which an obligation arises under clause 11.4; and
- preclude a failure to notify a distributor of a matter under clause 11.4 from being a ground for termination.

The distributors agreed to the first two of the proposed amendments and have amended their proposed terms and conditions to make the party's obligations subject to regulatory instruments, and include a new clause 11.4(a) requiring the user to notify the customer of it obligations under the regulatory instruments as set out in a new schedule 4.[540]

In relation to the third required amendment, the distributors noted that clause 12.2(a)(3) provides that a retailer's default in the performance of its obligations that causes material detriment to the distributor may lead to termination of the agreement where it is not remedied.[541] The distributors stated that whether the failure of a retailer to notify a distributor of a matter under clause 11.4 would cause material detriment is a matter that must be determined on a case-by-case basis.

The Commission now accepts the distributors' position that Clause 12 provides an appropriate mechanism for determining whether an agreement is terminated.

Accordingly, the Commission considers that the distributors' amendments to clause 11 are reasonable.

---

540 Multinet, Schedule 3.

541 Multinet, p.27; TXU, p.34; Envestra, p.12.

Clause 12 - Term and termination

Clause 12 prescribes the term of the proposed terms and conditions and sets out the grounds on which the agreement may be terminated. In the Draft Decision, the Commission supported Energex Retail's comment that the agreement should provide for termination if the distributor's licence is revoked, and required the distributors to amend clause 12 accordingly.

Each of the distributors has amended clause 12.6(b) of their proposed terms and conditions accordingly.

Clause 13 - Liabilities and indemnities

Clause 13 deals with warranties, indemnities and admissions, the procedure for notifying third party claims, and the preservation of certain statutory provisions.

Pulse Energy submitted that nothing in clause 13 should be allowed to exclude the operation of the GSLs. Pulse also recommended (and Energex Retail made similar proposals) that additional clauses be included in the same terms as:

- clause 13.2 of the EUoS (Liability for Supply) – the distributor indemnifies the retailer against certain matters relating to supply; and
- clause 13.3 of the EUoS (Non-Operation of Limitations of Liability) – the distributor is precluded from excluding its liability for claims made against the retailer by a customer to the extent that the retailer was prevented by law from excluding its liability for such claims at the time it entered into the contract with the customer. Such a clause would not apply to contracts with customers executed prior to the Commencement Date.[542]

In the Draft Decision, the Commission proposed that the distributors be required to amend clause 13.1 of their proposed terms and conditions to provide that nothing in clause 13 prevents the GSLs from operating, and to include clauses dealing with liability to supply and non-operation of limitations of liability. TXU Retail, Origin Energy, and AGL all supported the proposed required amendment.

In response, the distributors amended their proposed terms and conditions to include a new draft clause 13.1(b) to provide that nothing in clause 13 prevents the GSLs from operating. However, they also advised that they were not prepared to amend clause 13.2(a) and 13.2(b) as proposed by the Draft Decision on the basis that:

> Clause 13.2(b) of the EUoS would impose on the distributor a liability for claims under the Trade Practices Act (and equivalent State legislation) in circumstances where that legislation does not apply to services provided by the distributor to the user. The distributor has no management or control of the user– customer interface. In any event, clause 13.2(b) of the EUoS (as drafted) exposes the distributor to risks that it is not able to manage or control and for which it has not made a price allowance.[543]

Further, they argued that the clause would need to:

---

542 Draft Decision, p.195.

543 Multinet, p.29; TXU, p.35; Envestra, p.13.

- be confined to limit their liability to the performance or non performance of distribution services, under normal contracted supply terms;
- require the user to consult with the customer regarding risk and require the customer to implement appropriate risk mitigation measures; and
- abate the distributor's liability to the extent that the user contributed to the customers claim.

The distributors proposed the following amendment:

> Without limiting any other legal liability of a Service Provider, subject to the exclusions provided in sections 213, 233(1) or 233(3) of the GIA and the Gas Safety Act, the Service Provider shall indemnify the User against any:
>
> (b) Claim against the User by a Customer for breach by the User of any conditions, warranties or terms implied by Part V of the Trade Practices Act 1974 and equivalent State legislation in respect of the Supply by the Service Provider in relation to that Customer:
>
> (1) to the extent that the breach has not occurred as a result of the acts or omissions of the User;
>
> (2) where the User has by its conduct and in its Retail Contract with that Customer limited or excluded its liability to that Customer for breach of any of the conditions, warranties or terms implied by Part V of the Trade Practices Act 1974 and equivalent state legislation into that Retail Contract to the maximum extent permitted by that Act and by the Regulatory Instruments;
>
> (3) where the User has, at the Service Provider's request, delivered to the Customer any information published by the Service Provider concerning the inherent limitations in the quality and reliability of the Supply;
>
> (4) provided the User has not agreed to supply to the Customer Distribution Services in excess of the standard of Distribution Services to be supplied by the Service Provider to the User under this Agreement; and
>
> (5) provided that the User has consulted with the Customer as to the implementation of appropriate risk mitigation measures to minimise the potential for any Claim by the Customer under this clause, and the User:
>
> (i) implements and maintains such measures; and
>
> (ii) uses all reasonable endeavours to ensure that the Customer implements and maintains such measures.
>
> (c) The User must demonstrate to the Service Provider its compliance with its obligations under clauses 13.2(b)(2), 13.2(b)(3), 13.2(b)(4), and 13.2(b)(5) on reasonable request of the Service Provider from time to time.
>
> (d) The liability of the Service Provider under this clause 13.2(b) shall be reduced to the extent that the User has caused or contributed to the Claim.

(e) A Claim under this clause 13.2(b) will be a Claim for the purposes of clause 13.8(a).[544]

Retailers and distributors further discussed this issue at the Working Group meeting on 15 August 2002. In a submission, AGL Retail raised concerns that the distributors proposed amendment diverted unnecessarily from the arrangements in place for electricity, removing liability from the distributor, as the party best placed to manage such liability[545]. Its specific concerns related to proposed clauses 13.2(b)(1) and 13.2(b)(5). In particular, AGL claimed that clause 13.2(b)(1) limits indemnity to acts of the user, and thereby deprives it from having any real scope. Further, AGL considered that it was “not practical or workable” to require retailers to have consulted with customers regarding the implementation of appropriate risk management techniques, as proposed by clause 13.2(b)(5). Energex Retail also supported these comments.

With respect to AGL’s concern over proposed clause 13.2(b)(1), the Commission notes that distributors have amended the subclause to to read:

> To the extent that the breach has not occurred as a result of the acts of omissions of the user.

The Commission notes that the subclause is consistent with the EUoS and would – subject to the retailer complying with other provisions in the clause – indemnify the retailer against claims in respect of supply. As such, the proposed provision reflects, in the Commission’s view, an appropriate allocation of liability.

However, the Commission shares AGL’s concerns with respect to proposed clause 13.2(b)(5) in that it proposes to place onerous obligations upon retailers in relation to issues that are most appropriately managed by the distributor. As AGL pointed out, such issues could be managed, for example, by the distributors (through the retailer) under clause 13.2(b)(3). As such, and having regard to section 2.24(a), 2.24(c) and 2.24(f) of the Gas Code, the Commission requires distributors to delete this clause.

The distributors have amended clause 13.3 to preclude the distributor from excluding its liability for claims made against the retailer by a customer, to the extent that the law prevents the retailer from excluding its liability for such claims at the time it entered into the contact with the customer.

As noted in chapter 2, the Commission requires each of the distributors to delete clause 13.2(b)(5) of their proposed terms and conditions.

---

544 See clause 13.3 of the distributors’ revised terms and conditions.

545 AGL, Submission, 23 August 2002, p.5.

Clause 14 - Dispute resolution

Clause 14 sets out the procedures for resolving any disputes between the distributor and the user in relation to the Agreement. It provides for the dispute to be escalated between the organisations, before resorting to mediation or arbitration. Energex Retail suggested that clauses 14.1(a) and (b) should be deleted, but failed to provide supportive reasoning. It also argued that clause 14.6 should preserve the Commission's jurisdiction to determine the fairness and reasonableness of an offer made under the Agreement.

In the Draft Decision, the Commission indicated that it did not consider it appropriate to delete clauses 14.1(a) and (b), as this would have the effect of excluding the operation of dispute resolution procedures approved by the Commission under the Gas Distribution System Code, as well as those that apply by virtue of the Gas Code. However, the Commission required the distributors to include a clause providing that nothing in clause 14 would derogate from the Commission's jurisdiction to determine the fairness of any offer made in accordance with the distributor's licence or the application of any guidelines.

The distributors argued that it is not appropriate to require them to include a clause based on clause 14.6 of the EUoS, as there is nothing current or proposed in the gas distribution licences to which it would relate.[546] Further, they argued that the intent of the requested amendment is met within the framework of the Gas Code, which allows for parties to negotiate agreements and for the Commission to arbitrate any disputes and to apply the approved terms and conditions.

The Commission considers that further amendment to this clause is not required on the basis that there is nothing current or proposed in the gas distribution licences on which this clause would impact.

Clause 15 - Representations and warranties

Clause 15 sets out the representations and warranties to be given by each party to the other. In the Draft Decision, the Commission noted Energex Retail's argument that the warranty given by a retailer under clause 15.1(b) that it has the right to have gas delivered to the transfer point should be expressed more broadly as a right to have gas delivered. Pulse Energy and Energex Retail also recommended that clause 15.3(d), under which each party represents that at the date of the agreement an Insolvency Event '*has not occurred'*' in respect of that party, should be deleted.

In the Draft Decision, the Commission proposed that each of the distributors be required to amend clause 15 of its proposed terms and conditions to firstly, more generally express a retailer's right to have gas delivered and secondly, to delete clause 15.3(d) with respect to retailer warranties.

With respect to the first proposed amendment, the distributors claimed:

546 Multinet, p.30; TXU, p.36; Envestra, p.13.

> A distributor is not concerned with any warranty in relation to the ability to deliver gas from the transfer point to a distribution supply point, since such a service is the subject of the access arrangement and the agreement with the distributor. The distributors' concern is the ability of the User to have gas delivered to the transfer point.[547]

The Commission accepts the distributors' position on this matter and does not require further amendment to clause 15.1.

The Commission also notes that the distributors have amended clause 15.3(d). As a result, the Commission does not require any further amendment to this clause.

Clause 19 - General

Clause 19 contains provisions relating to other matters relevant to the proposed terms and conditions, such as waiver, amendment, attorneys, severability, counterparts, further assurance, assignment, the accumulation of remedies, costs and schedules.

In the Draft Decision, the Commission noted that Envestra's proposed terms and conditions for its Victorian and Albury networks did not contain a provision (equivalent to clause 19.2(b) of Multinet and TXU's proposed terms and conditions) providing that where the regulator approves an amendment to the terms and conditions in response to a revision submitted by a service provider, the parties agree to amend their agreement in the same way. In the Draft Decision, the Commission required Envestra to amend its proposed terms and conditions to include a clause in the same terms as clause 19.2(b) of TXU's and Multinet's terms and conditions.

In response, Envestra has amended clause 19 of its proposed terms and conditions to include a similar provision. As a result, the Commission does not require any further amendment to Envestra's proposed terms and conditions.

---

547 Multinet, p.31; TXU, p.37; Envestra, p.14.

Appendix C Cost of Capital

C.1 Introduction

C.1.1 Gas Code requirements

Sections 8.30 and 8.31 of the Gas Code require the return (*Rate of Return*) on the regulatory value of the distributors' assets (the capital base) that is factored into reference tariffs to comply with the following principles:

> The Rate of Return used in determining a Reference Tariff should provide a return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the Reference Service (as reflected in the terms and conditions on which the Reference Service is offered and any other risk associated with delivering the Reference Service).
>
> By way of example, the Rate of Return may be set on the basis of a weighted average of the return applicable to each source of funds (equity, debt and any other relevant source of funds). Such returns may be determined on the basis of a well-accepted financial model, such as the Capital Asset Pricing Model. In general, the weighted average of the return on funds should be calculated by reference to a financing structure that reflects standard industry structures for a going concern and best practice. However, other approaches may be adopted where the Relevant Regulator is satisfied that to do so would be consistent with the objectives contained in section 8.1.

The first provision requires the implied return factored into the assessment of the price controls for the distributors' regulated activities to reflect the opportunity cost of capital associated with those activities. The second provision provides additional guidance on how to estimate the cost of capital associated with the distributors' regulated activities. It specifically allows for returns to be determined on the basis of a well-accepted financial model, such as the Capital Asset Pricing Model (CAPM). This model is discussed further below. It also encourages the use of benchmarks for such matters as financing arrangements – which is discussed further in section C.6 below.

The *opportunity cost of capital* associated with an asset is the return investors would expect to receive from that project in order to justify committing funds.[548] In turn, this depends upon the aggregate demand and supply of investment funds, as well as the risk of cash flows generated by the project relative to the risk associated with other assets. Unlike the price for most goods and services, the market price for investment capital cannot be observed. Rather it needs to be *estimated* from information available from the capital markets. It is important to note that neither the company, the regulator nor customers can determine the cost of capital — it is a market price for investment funds that can only be inferred from the available evidence. The cost of capital for an asset is often referred to as the weighted average cost of capital, given that the limited information available from capital markets implies that the costs of capital needs to be inferred from the returns required by the different forms of finance supplied – namely, debt and equity.

In its previous consultation papers and in the Draft Decision, the Commission noted that estimating the cost of capital for regulated businesses has generated a degree of controversy, both for the Commission and other Australian economic regulators. In part, this reflects the fact that the cost of capital assumed in setting regulated charges can have a significant impact on prices, and hence revenue to the businesses. This controversy also reflects the fact that there is a degree of statistical uncertainty associated with any of the models drawn from finance theory and practice. Accordingly, some imprecision in deriving the estimate and the exercise of judgment is inevitable. This statistical uncertainty, coupled with the divergent interests of the regulated entities, customer groups and independent regulators, implies that it is unlikely that there could be full agreement on the exercise of that judgment.

In its previous consultation papers and in the Draft Decision, the Commission presented its views on two principles it considered relevant for guiding the estimation of the costs of capital associated with the distributors' regulated activities. First, the Commission has emphasised that given the objective of estimating the market price for investment funds, primacy should be given to *objective evidence from capital markets* where that evidence is available. Second, any model drawn from finance theory and practice must be applied *consistently* across the whole of the estimation process. However, the Commission has also noted that the latter principle does not preclude verifying the estimate of the cost of capital that is delivered by a consistently-applied model against other objective evidence of the price on investment funds. In contrast, the Commission has emphasised repeatedly the need for judgment to be exercised, and all available (and relevant) information to be taken into account.

548 The term *weighted average cost of capital* (WACC) is often used to refer to the cost of capital of an asset because part of the asset returns become payments to the debt providers, and the residual flows to the equity providers. The Commission uses the terms 'cost of capital' and WACC interchangeably throughout this document.

In the Draft Decision, the Commission noted that the distributors appeared to accept the principles of reliance on capital market evidence and consistency either explicitly or implicitly,[549] and the submissions received in response to the Draft Decision did not express reservations with the principles.[550] In the Draft Decision, the Commission also addressed the concern raised by the distributors in their submissions that the Commission's analysis should be is consistent with commercial best practice. While the Commission has considered such evidence where it has been produced and is relevant, it notes that its principal concern is to adhere to the requirements of the Gas Code, in particular, the guidance from section 8.30 that a reference tariff should provide a return that 'is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the reference service'.[551]

C.1.2 Structure of this appendix

In its previous consultation papers and in the Draft Decision, the Commission has distinguished two issues from those associated with the cost of capital, namely the assumption made about company tax liabilities, and the question of whether the price controls may deliver a lower return than the cost of capital because of 'excluded events'.[552]

With respect to taxation, the models drawn from finance theory and practice for estimating costs of capital provide an estimate of the *after-tax WACC* for a project. In contrast, the price controls to be incorporated into the distributors' revised access arrangements need to include an allowance in relation to the distributors' company tax obligations. Accordingly, an assumption needs to be made about the taxation liabilities incurred in providing the regulated services over the regulatory period. However, there are different issues associated with estimating the cost of capital associated with an asset and deriving an allowance for taxation. Accordingly, the Commission has discussed taxation separately in section C.8.

Separately estimating the after-tax cost of capital and the allowance for taxation has implications for the WACC-formula (as well as the formula used to derive revenue targets). The WACC formula proposed by the Commission (and adopted in the distributors proposals) excludes all tax-related matters as is represented as follows:

$$WACC = R_e \frac{E}{V} + R_d \frac{D}{V}$$

where Re, Rd, are the costs of equity and debt respectively, and E/V and D/V are the shares of equity and debt in the financing structure of the asset.

549 Draft Decision, p.205.

550 Clearly, the distributors have expressed a number of concerns with the Commission's application of these principles, which are discussed in the relevant section throughout this chapter.

551 Gas Code, section 8.30.

552 Op. cit., Consultation Paper No. 1, pp.50-51; Position Paper, pp.37, 40-43; Draft Decision, p.203.

In relation to 'excluded events', the Commission has noted in its previous consultation papers and in the Draft Decision that a cornerstone of modern finance is that much of the risk (or volatility) associated with the earnings to a particular asset can be eliminated at no cost merely by holding that asset as part of a diversified portfolio. Such *diversification* implies that only that portion of risk that is associated with economy-wide events affects the cost of capital: as the remaining volatility in an asset's earnings can be eliminated at no cost, investors cannot command a return for accepting the risk associated with events that are unique to a particular asset. The Commission has previously provided a detailed discussion of its framework for analysing risk, including a discussion of the relevance of *hedging* in deriving the price controls.[553]

However, throughout its discussion of the analysis of risk, the Commission has noted that a separate issue relates to whether the return that investors should expect under the new price controls corresponds to the estimate of the cost of capital. In principle, this requires a view to be taken of at least the impact on expected returns of all events that may not have been considered in the expenditure and revenue forecasts – which the Commission has referred to as 'excluded events'.[554] In the Draft Decision, the Commission provided a detailed discussion of the distributors' proposals. The preliminary conclusions reached in the Draft Decision, and the distributors' further submissions on this matter, are discussed in section C.9.

C.2 Method of estimating the after-tax WACC

C.2.1 Background and distributors' proposals

In the Draft Decision, the Commission used the Capital Asset Pricing Model (CAPM) to guide the estimation of the costs of capital associated with the distributors' regulated activities. The Commission used the CAPM for this purpose in its 1998 decision, it has been used extensively in Australia and the UK, CAPM is widely used by the Australian finance community, and was used by the distributors to derive their cost of capital estimates. In their responses to the Draft Decision, all of the distributors expressed continued support for the use of the CAPM. Accordingly, the Commission has adopted this model in this Final Decision.

In their submissions, all of the distributors emphasised shortcomings with the CAPM, including the degree of statistical uncertainty associated with the estimation of a number of its inputs (as the Commission has noted already above), as well the restrictive nature of a number of the assumptions underpinning the theoretical model. The distributors' proposed response to the uncertain and restrictive assumptions associated with the CAPM is for the Commission to apply a conservative (that is, a pro-investor) judgment, as well as to check the estimates provided by the CAPM against other evidence of required investor returns.

553 Op. cit., Further Guidance to the Distributors, Appendix A; pp.55-58
554 ibid., pp.52-55.

In the Draft Decision, the Commission noted that it had only accepted the use of the CAPM as the most appropriate model *at this point in time*. It noted that, given that finance theory is constantly evolving, the use of an alternative model or models of shareholder returns in the future should not be ruled out. Consistent with this, the Commission required the distributors to delete a fixed principle from their proposed Revisions that would have required the continued use of the CAPM for another 30 years.[555] The issues associated with this fixed principle are discussed separately in section 5.1.7.

C.2.2 Description of CAPM

In its simplest form, the CAPM provides a direct estimate of the required return for a project. That is:

$$R_a = R_f + b_a(R_m - R_f)$$

> where R_a is the required return on assets (WACC), R_f is the risk free rate, β_a is the asset beta, and (R_m-R_f) is the return in excess of the risk free rate that investors would need to expect in order to hold the well-diversified portfolio of assets.

The *beta* reflects the level of non-diversifiable risk associated with a particular asset, relative to the (non-diversifiable) risk associated with the well-diversified portfolio of assets.[556] A beta of less than one implies that the particular asset has less non-diversifiable risk than the market average, and vice versa for assets with a beta that is greater than one. A well-diversified portfolio has a beta of one.

In practice, asset betas cannot be observed or measured directly. Estimating a beta requires information on the economic returns on individual assets (comprising the value of the returns plus the change in the market value of the asset) as well as the economic return on the well-diversified portfolio of assets.[557] As this information is only available for assets that are traded on a stock exchange, in practice, the CAPM is used to estimate the required return to the *equity* share of an asset, and stock market indices are used as a proxy for the market portfolio. Accordingly, the more common formulation of the CAPM is the following:

$$R_e = R_f + b_e(R_m - R_f)$$

---

555 The Commission noted that the distributors' desires to lock in the continued use of the CAPM appeared inconsistent with their concerns about the performance of the model for describing security returns: Draft Decision, p.103.

556 The level of non-diversifiable risk associated with an asset can be interpreted as the extra (or incremental) risk an investor would face if it adds the asset in question to a well-diversified portfolio of assets. This result follows because any diversifiable risk associated with the asset is eliminated when combined with the portfolio of assets – leaving only the non-diversifiable component behind. Note also that the *non-diversifiable* and *total risk* associated with the market portfolio are the same because the diversifiable component of the risk would have disappeared as a result of combining the assets into a portfolio.

557 In principle, the market risk premium should reflect the risk premium required for holding a portfolio of all assets in the economy (eg equity, bonds, property and human capital). The use of traded equities is a proxy for all assets.

where Re is the required return on equity, βe is the equity beta, and (Rm-Rf) is now the return over the risk free rate that investors would need to expect in order to invest in a well-diversified portfolio of equities (the equity (market) risk premium).

The beta now reflects the non-diversifiable risk of an equity compared to the portfolio of equities.

A proxy for the cost of debt financing is then normally taken from the promised yield on debt (either observed or estimated), the level of gearing of the entity is observed, and the WACC estimated as the weighted average of the costs of these different sources of finance.

Accordingly, the application of this methodology requires assumptions to be made about the following the real risk free rate of return, equity (market) risk premium, proxy beta, and cost of debt and capital structure. The issues associated with these inputs are discussed in turn below.

C.3 Risk free rate

C.3.1 Background and distributors' proposals

Where regulated prices are escalated for actual inflation over a regulatory period (and regulatory asset values are escalated for actual inflation), the *real* (rather than nominal) risk free rate is the important input to the estimation of the cost of capital.[558]

As the Commission noted in the Draft Decision, while the method for deriving the real risk free rate was controversial during its 1998 review, since that time, a reasonably uniform practice has emerged amongst Australian regulators whereby the real risk free rate is derived as a recent average (over 20 or 40 days) of the redemption yield (with terms to maturity of either 5 or 10 years) on long-dated inflation-indexed Commonwealth Government securities. The real risk free rate adopted when the current price controls were determined in 1998 was determined with reference to the recent average of yields on inflation-indexed bonds.[559]

558 That is, where tariffs are escalated for inflation, then a real return to investors is provided (and the real risk free rate is the relevant measure of the risk free rate), irrespective of how the regulator chooses to express its estimate of the cost of capital.

559 Op. cit., 1998 Final Decision, p.201. As noted in the Draft Decision, most other Australian regulators derive a nominal risk free rate as a recent average of nominal bonds (and express required returns in nominal terms), and then adopt a forecast of inflation as the difference (using the Fisher transformation) between this yield, and the yield on inflation-indexed bonds. The result is virtually identical to just taking a direct observation of the real risk free rate and expressing required returns directly in real terms (as noted in section 3.6, the Commission's methodology results in a slightly higher estimate of the cost of capital for the same set of inputs than the alternative method).

In its earlier consultation papers, the Commission proposed using the yield on inflation-indexed bonds to provide a direct estimate of the real risk free rate, and to derive estimates of the real costs of equity and debt directly. It proposed using inflation-indexed bonds with a term to maturity of 10 years, and sampling yields over the latest practicable 20 trading-day period prior to determining new price controls. It also proposed deriving an inflation forecast by taking the difference (using the Fisher transformation) between the yield on nominal and inflation-indexed bonds although, as noted above, the forecast of inflation has second-order significance if the real risk free rate is observed directly.

In their submissions, TXU and Multinet proposed methods for deriving a real risk free rate that were substantially similar to those of the Commission. As there were no inflation-indexed bonds with a 10 year term to maturity, a proxy was taken as a linear interpolation between the bonds that have terms around this date, with the yield estimated for a bond with a 10 year term from 1 January 2003. TXU used the mid-point of the Reserve Bank of Australia target range (2.5 per cent) as its forecast of inflation, while Multinet did not identify its assumption, although both of these companies noted that the implied nominal returns to debt providers should be benchmarked against the current cost of borrowing in fixed rate nominal terms in order to ascertain whether there would be a bias against businesses that were constrained to borrow in this manner.[560]

In contrast, Envestra derived a real risk free rate as the difference between the yields on nominal Commonwealth Government securities with a term to maturity of ten years averaged over a 20 day period, less its forecast of inflation (using the Fisher transformation). It used a forecast of inflation of 2.5 per cent, which was taken as the midpoint of the Reserve Bank of Australia's target range. Envestra had previously expressed a concern with using the difference between nominal and inflation-indexed bonds to provide a forecast of inflation.[561] Under Envestra's proposed method of deriving a real risk free rate, its forecast of inflation is a significant issue.

---

560 Following the format of the Draft Decision, this issue addressed in section C.6.

561 Envestra, Response to Consultation Paper No. 1, July 2001, p.13.

C.3.2 Draft Decision

In the Draft Decision, the Commission used a recent average of inflation-indexed bonds to obtain a direct proxy for the real risk free rate. It noted that this method was consistent with the guiding principle discussed above of relying upon direct observations from capital markets to the extent possible. It noted that the method proposed by Envestra would imply that the forecast of inflation adopted is a significant issue – and that Envestra's proposed forecast (the mid-point of the Reserve Bank target range, 2.5 per cent) is only one of the available forecasts, and that the alternatives vary substantially. It was also noted that one of the problems with using inflation forecasts from institutions is that they are updated infrequently and so may not reflect the latest information. Lastly, the Commission noted that the only distributor to propose an alternative approach was Envestra, who recently accepted this methodology for the determination of a risk free rate in relation to its Queensland gas distribution network.[562]

On a technical matter, the Commission noted that there are no bonds with a ten-year term to maturity currently, and accepted TXU and Multinet's proposal to calculate a yield for an implied ten year bond by taking a linear interpolation of the yields on the available bonds. However, the Commission noted that the yield should reflect a bond with a term of ten years from the date of observing its yield, rather than 10 years from 1 January 2003, as proposed by TXU and Multinet (although the difference is unlikely to be material).

The result from the application of this methodology in the Draft Decision was a real risk free rate of 3.5 per cent (rounded to one decimal place) and a forecast of inflation of 2.7 per cent (rounded to one decimal place).

C.3.3 Responses to Draft Decision

TXU and Multinet's submissions in response to the Draft Decision supported its approach to deriving the real risk free rate and forecast of inflation, subject to the caveat about the implied nominal return to debt providers referred to above.[563] In contrast, Envestra noted that its views about the method for deriving the risk free rate were unchanged, although it did not present any further argument or material on the issue.[564]

---

562 Envestra, Access Arrangement for the Queensland Distribution Network: Envestra Limited Response, May 2001, p.39; and Queensland Competition Authority, Proposed Access Arrangements for Gas Distribution Networks: Allgas Energy Limited and Envestra Limited: Final Decision, October 2001, p.242.

563 TXU, Response to the Draft Decision, Attachment C, pp. 14, 19; Multinet, Response to the Draft Decision, Attachment D, pp. 14, 19.

564 Envestra, Response to the Draft Decision, p.40.

C.3.4 Further analysis

The Commission has employed the same methodology for deriving the proxy for the real risk free rate and forecast of inflation in this Final Decision as it did in the Draft Decision. As no further contentions have been made, its reasons for adopting this assumption are the same as those provided in the Draft Decision, as summarised above. The most important of the reasons provided was that this method makes the greatest use of objective market evidence, and in particular, reduces the significance of inflation forecasts (for which there are a number of forecasts available, which have substantial variation). To illustrate this point, table C.1 reproduces a number of the current inflation forecasts upon which weight could be placed.

TABLE C.1
CURRENT INFLATION FORECASTS

Source				
Medium Term Forecasts	**2002-03**	**2003-04**	**2004-05**	**2005-06**
Access Economics (Sept 2002)	2.8%	2.5%	3.3%	1.6%
Victorian Treasury (May 2002)	2.25%	2.25%	2.25%	2.25%
Commonwealth Treasury (May 2002)	2.75%	2.5%	2.5%	2.5%
Other Forecasts				
Last 12 months (% change in CPI) [565]	2.8%			
Melbourne Institute / Westpac [566]	4.4%			
Reserve Bank Target Range	2% - 3%			

Regarding the timing over which interest rates were sampled, the Commission noted in the Draft Decision that it would take the latest practicable 20 trading days prior to issuing the Final Decision, and the intervals adopted in previous decisions would have suggested the use of the last 20 trading days of August. However, during the course of the review, the Commission received a request that the interval be deferred one week (to the week ending 6 September 2002) in order to permit new financing or hedging arrangements to be put in place, which was accepted in this instance. The Commission considers it undesirable to respond to requests regarding the sampling interval during the course of the review, and prior to its next review of the gas access arrangements will consider the extent to which its intentions over the sampling interval can be announced in advance.[567]

565 This is percentage increase in the CPI (average of eight capital cities) over the year to the June quarter 2002.

566 This number represents a survey of consumer expectations of inflation for the year from May 2002.

567 Due to rounding, the change in the sampling interval did not affect either the real risk free rate or the debt margin assumed.

Accordingly, for the purposes of this Final Decision, the Commission has sampled interest rates over the 20 trading days to 6 September 2002, taking a linear interpolation of the available interest rates to derive a bond with a remaining term of 10 years from the observation date. This generates a proxy yield of 3.4 per cent (rounded to one decimal place). With respect to the forecast of inflation, the Commission had used the break-even rate of inflation between nominal and inflation-indexed bonds of the same term to maturity and averaged over the same period. The average yield on nominal bonds was 5.7 per cent (rounded to one decimal place), which implied a forecast of inflation of 2.2 per cent (rounded to one decimal place).

The Commission notes that, at this time, the use of a direct observation of the real risk free rate from inflation-indexed bonds has lead to a *higher* real risk free rate being used than would have been the case had the mid-point of the Reserve Bank target rate been taken as the inflation forecast and deducted from the nominal bond yield (the difference being 0.3 percentage points).[568] The Commission's method for deriving the proxy real risk free rate in its 1998 decision was also weighted towards the interests of distributors (in the 1998 review, the difference between the methodologies was almost 0.5 percentage points).[569]

C.3.5 Final conclusions

The Commission has used the average redemption yield over the last 20 trading days to 6 September 2002 for an inflation-indexed bond with a 10 year term to maturity as the proxy for the real risk free rate. As the bonds with the closest term to maturity to ten years mature in August 2010 and August 2015, a proxy for the yield on a ten-year bond has been determined as a linear interpolation between these dates. This provides a proxy for the real risk free rate of 3.4 per cent.[570]

The Commission has used the difference between the redemption yield on nominal bonds and inflation indexed bonds (using the Fisher transformation) of the same term over the same period to derive a forecast of inflation. The proxy yield for nominal bonds was also derived as a linear interpolation of the yields for the securities with the closest terms to maturity (June 2011 and May 2013), and the average over the last 20 trading days to 6 September 2002 was 5.7 per cent, resulting in a forecast for inflation of 2.2 per cent.

---

568 Envestra's submission to the Draft Decision continued to advocate the difference between nominal bond yields and the mid-point of the Reserve Bank target range to derive a real risk free rate, notwithstanding that the application of this method would not be in its interest at this point in time (Envestra, Response to the Draft Decision, p.50.

569 Op. cit., 1998 Final Decision, p.201.

570 Data provided by the Reserve Bank of Australia, 9 September 2002.

C.4 Equity premium

C.4.1 Background and distributors' proposals

As measured and applied in practice, the market risk premium that is used in the CAPM is the premium in excess of the risk free return that investors expect to earn from a well-diversified portfolio of equities, which is also commonly known as the equity premium. The equity premium is one of the most important quantities in finance – it is an essential input into the CAPM, and is also essential to decisions on the allocation of savings (such as superannuation funds) between shares and other asset classes. A view on future returns to stocks (and therefore the equity premium) is also an essential input into the decision about how much Australian households need to save out of current income in order to provide for their desired standard of living in retirement, which has been the subject of recent public debate.

The equity premium is also one of the most debated quantities in finance, with the magnitude of the premium, the appropriate method of estimation, as well as the theoretical validity of the various empirical estimates subject to significant debate. However, as the Commission's primary concern is to obtain an unbiased estimate of the magnitude of the premium, the last of these debates – that of the ability of theory to explain the observed returns – is not directly relevant.

In its previous consultation papers, the Commission has noted that there are a number of methods that have been used to estimate the (expected) equity premium. It was noted that the most commonly advocated approach is to use a long-term average of realised equity returns (net of the return on a risk free instrument). However, it was also noted that this method has a number of weaknesses, including that actual returns have a large annual variation such that the estimates are generally imprecise. In addition, an implicit assumption of this approach is that the premium has not changed over the period of estimation.

All of the distributors proposed placing most weight on the long-term historical average of equity returns. However, in reflection of the inherent imprecision associated with estimating the equity premium, there was a large spread in the distributors' proposals – TXU proposed the use of a 6 per cent equity premium, Multinet 7 per cent, and Envestra proposed 7.3 per cent.[571] In justifying their proposals, the distributors referred to a number of different estimates of the historical premium to equity in Australia, which are discussed further below.

The distributors also referred to the report commissioned by Professor Gray in response to the Position Paper.[572] In that paper, Gray presented a statistical test of the proposition that the equity premium has fallen, and concluded that there is no evidence of such a fall. He also discussed the use of *ex ante* models for estimating the premium, and concluded that these estimates also have low precision. Notwithstanding, he noted that an estimate using data over 1990-2000 and GDP growth as a proxy for dividend growth, resulted in an estimate close to 6 per cent.

---

[571] TXU and Multinet's proposals differed by 1 percentage point notwithstanding that both referred to precisely the same evidence on the premium.

[572] Gray, S., 2001, Issues in Cost of Capital Estimation.

Professor Gray also summarised other evidence, including evidence from surveys and the implications of extrapolation from foreign markets. Gray also discussed the attempts in the literature to forecast the equity premium based upon macro-economic variables, and dismissed the use of such approaches as having poor ability to predict the premium out of sample. Gray then referred to the ability of the theory to explain the premium and noted that recent theoretical advances may be able to explain much of the historically observed premium.

C.4.2 Draft Decision

In the Draft Decision, the Commission noted that it has placed weight on the long-term average of historical equity returns, as proposed by the distributors. However, in the Draft Decision, it noted that the variability in annual equity returns makes the estimate of the expected equity premium from actual share market returns subject to a large degree of uncertainty. For this reason, the Commission took account of other information on the expected equity premium in the Draft Decision. The views presented in the Draft Decision on the information provided by historical returns, the other information that was taken into account, and the Commission's conclusions are discussed in turn below.

Historical premia to equities

The Commission clarified what it considered was the estimate of the equity premium that is derived from the long-term average of the historical premia to equities. It noted that the distributors' submissions had referred to a number of different values as representing the estimate derived from the long-term average of the historical premium to equities (over the returns on 'risk free' assets), or to studies that provided other estimates of the equity premium that appeared to reflect a long-term average.[573] As all of these studies appeared to draw upon the same data set, it was noted that these differences could only result from differences in averaging technique, or in the sample period.

The most authoritative work in Australia on the historical returns from stocks and bonds is the study first undertaken by Professor Officer, with updated results obtained by the Commission.[574] The table from the Draft Decision showing the realised equity premium as measured by this data set, updated to the end of 2001, is replicated below.

---

573 For example, TXU and Multinet referred to eight estimates of the premium, six of which are understood to rely upon the long run average of equity returns (op. cit., TXU, p.20; Multinet, p.17). Envestra referred to a long term average for Australia (from various sources) of 8 per cent, 7.3 per cent, 7.1 per cent to 8.6 per cent, and to 8.6 per cent or 8.1 per cent (Envestra, 2002, Access Arrangement Information, p.A20).

574 Officer, R., 'Rates of Return to shares, bond yields and inflation rates: An historical perspective', in *Share Markets and Portfolio Theory; Readings and Australian Evidence*, 2ed, University of Queensland Press, 1992.

TABLE C.2

HISTORICAL AUSTRALIAN EQUITY PREMIUM – 1882 TO 2001

Time period	Equity Premium: Returns	Standard Deviation	Standard Error of the Mean
1882-2001	7.19%	16.97%	1.55%
Different Ending Point:			
1882-1950	8.00%	11.11%	1.34%
1882-1970	8.16%	13.70%	1.45%
1882-1990	7.40%	17.33%	1.66%
Different Beginning Point:			
1900-2001	7.14%	17.94%	1.78%
1950-2001	6.51%	22.60%	3.13%
1970-2001	3.37%	24.38%	4.31%

Source: Information in the first three columns provided by Professor Officer. Original information published in Officer, R., 'Rates of Return to shares, bond yields and inflation rates: An historical perspective', in *Share Markets and Portfolio Theory; Readings and Australian Evidence*, 2nd edition, University of Queensland Press, 1992.

However, the Commission noted that its assumption about the value of franking credits requires an upward adjustment to the measured cash equity premium to add back the non-cash value of franking credits since 1987 – which the Commission has estimated to add 0.2 percentage points onto the long term average.[575] Accordingly, the imputation-adjusted long-term average was 7.3 per cent, with a 95 per cent confidence interval of 4.3 per cent to 10.4 per cent. The yield on bonds was used as the measure of the risk free return.[576]

In the Draft Decision, the Commission noted that the distributors and Professor Gray (in a submission commissioned by the distributors) had referred to the historical average of equity premia in the US. The Commission noted that it had previously expressed concern with drawing inferences for the Australian equity premium from estimates of the premium for other countries, but that comparisons with the US are inevitable, given that much of the academic research into the premium has focussed on the US market. Accordingly, it summarised the estimates of the equity premium that are provided by the long-term average of equity returns in the US. Table C.3 replicates the results reported in the Draft Decision.

575 This estimate assumes a value of franking credits once distributed of 0.6 (as a proportion of face value), a constant franking ratio of 83 per cent over the period (which is taken from Hathaway, N., R. Officer, 1996, The Value of Imputation Tax Credits, working paper, Melbourne Business School, p.12) and uses the prevailing corporate tax rate and dividend yield for each year.

576 The Draft Decision also considered the estimates of the equity premium presented in Dimson, E, P Marsh and M Staunton, 2000, Twelve Centuries of Capital Market Returns, working paper, which were interpreted as either 6.5 per cent, 7 per cent or 7.6 per cent. However, the Commission expressed concern with two methodological steps in the calculation of these averages, and so did not place weight on these estimates: Draft Decision, pp.14-15.

TABLE C.3
HISTORICAL US EQUITY PREMIUM – 1802 TO 2000

Source	Period	Equity Premium	Standard Error
Siegel (1992)	1802-1992	5%	1.5%
Pastor and Stambaugh (2001)[a]	1834-1999	5.8%	Unreported
Fama and French (2002)[a]	1872-2000	5.6%	1.6%
Ibbotson (2001)	1926-2000	7.76%	Unreported
Fama and French (2002)[a]	1951-2000	7.4%	2.4%

a The premium presented is measured against 6 month bills.

Sources: Siegel, J., 'The Equity Premium: Stock and Bond Returns Since 1802', Financial Analysts Journal, Jab-Feb, pp. 28-38, quoted in Lally, M., 2000, *The Cost of Equity Capital and its Estimation*, McGraw Hill Series in Advanced Finance, vol. 3, (McGraw Hill, Sydney), p.19; Pastor, L. and R. Stambaugh, 2001, 'The Equity Premium and Structural Breaks', *The Journal of Finance*, Vol. LVI, No. 4, p.1225; Fama, E. and K. French, 2002, The Equity Premium, *The Journal of Finance*, Vol LVII, no. 2, p.641, table 1; Ibbotson Associates, 2001, International Cost of Capital Report 2001, quoted in Gray, S, 2001, Issues in Cost of Capital Estimation, p.13.

While the Ibbotson estimates (that is, covering the period 1926 onwards) are typically quoted as the long-term average of the US equity premium, it was noted that the distributors' arguments in favour of a long averaging period would suggest that the longest series of information should be considered when estimating the equity premium for the US. It was noted that while the reliability of some of the information prior to 1834 could be doubted,[577] there is no compelling reason to restrict attention to the period after 1926. The period covered in the Fama and French (2002) study was noted as the closest to that covered in the Professor Officer data set for Australia, and so its estimate of 5.6 per cent (against 6 month bills) was taken as the long term historical average equity premium in the US, with a 95 per cent confidence interval of 2.5 per cent to 8.7 per cent.[578]

The Commission then noted a number of concerns that have been advanced with the use of a historical average. First it noted that, consistent with the discussion above, these estimates have a large standard error – which, as discussed above, is why the Commission considers it desirable also to take account of other information. Secondly, the Draft Decision referred to the argument that unexpected inflation since the second world war may have lead to a downward bias to real returns on bonds (but not stocks), thus biasing upwards the measured equity premium.[579] Thirdly, it was noted that in order to obtain an estimate of the equity premium with even the wide standard error reported above, a long period is required – 120 years in the results above – and it was noted that numerous reasons have been advanced as to why the premium may have changed over this time.[580]

---

577 Pastor, L. and R. Stambaugh, 'The Equity Premium and Structural Breaks', *The Journal of Finance*, Vol. LVI, No. 4, 2001, pp.1218-1219.

578 The equity premium measured against bonds (as the Commission has adopted) would be expected to be lower.

579 By way of example, it was noted that the arithmetic average of real bond yields in the data set used to derive the historical equity premium for Australia that was referred to above was approximately 2 per cent, which compared to the prevailing real bond yields of 3.5 per cent, or 3.4 per cent at the time of this Final Decision. The Commission noted in the Draft Decision that Siegel observed that real equity returns appear to be stable over time, and that the equity premium can be estimated by deducting the prevailing real risk free rate from that historical average (Siegel, J., 1992, 'The Equity Premium: Stock and Bond Returns Since 1802', *Financial Analysts Journal*, Jan-Feb, pp. 28-38). The Dimson et al arithmetic average of real equity returns over 1901 to 2000 was 9.1 per cent. Given a current real risk free rate of

Regarding the validity of the use of a long-term average in light of the second and third concerns discussed above, the Commission considered two pieces of statistical evidence about the behaviour of the historical equity premium. The first was a series of simple t-tests performed by Professor Gray on the sample means of various sub-periods, which failed to find any evidence of a statistically significant change in the premium. The second was an application of the augmented Dickey-Fuller test performed by Envestra, which rejected the hypothesis that the historical premium to equities is generated by a non-stationary process.

In assigning weight to the first of these pieces of evidence, the Commission noted first, that a general problem with the application of empirical tests to actual equity returns in general is that the variability in annual equity returns makes it very difficult to discern changes to the underlying expected equity premium. Specifically in relation to the test performed by Professor Gray, this meant that while a lot of comfort could have been taken if the hypothesis of 'no change' had been rejected, the failure to reject the hypothesis does not provide much positive for the proposition that the mean has remained unchanged.[581]

In addition, the Commission noted that the use of actual equity returns to attempt to detect a change in the expected equity premium is subject to an inherent bias, which has been recognised by other finance researchers.[582] The bias arises because if the *expected* equity return were to fall (rise), then share prices would be expected to rise (fall), thus creating a shock to *measured* equity returns in the opposite direction. It was demonstrated that the shock to the measured equity returns could be large enough to make a change in the expected equity premium undetectable, even if a reasonable number of observations after the change in the premium were used.[583]

Notwithstanding these observations, the Commission noted that it considered that its approach of using the average of historical equity premia to set the bounds for the expected equity premium, but to use other information to refine the point within that range, is consistent with an assumption that the expected equity premium has not changed.[584]

3.4 per cent, implies an estimate of the equity premium of 5.7 per cent, or approximately 6 per cent once an adjustment is made for the non-cash value of imputation credits since 1987 (Dimson, E, P Marsh and M Staunton, 2000, Twelve Centuries of Capital Market Returns, working paper, table 2).

580 Some of the factors that may have changed that have been suggested include a reduction in the cost of holding a well-diversified portfolio of assets, a fall in the rate of investor taxes (caused by, amongst other things, the increasing prominence of low-taxed entities, such as super funds), a rise in the prominence of younger investors (for whom stocks carry less risk because expected future income occupies a greater proportion of their wealth) and a reduction in market imperfections generally that may have caused higher historical premia.

581 In statistical terms, the test performed by Professor Gray would be expected to lack power, or alternatively, that the probability of making a type II error is expected to be high: Draft Decision, p.217.

582 Reference was made to Pastor, L. and R. Stambaugh, 'The Equity Premium and Structural Breaks', *The Journal of Finance*, Vol. LVI, No. 4, 2001, pp.1218-1219.

583 It was noted that if expected share market returns fell from 12 per cent to 11 per cent as a result of a one percentage point fall in the equity premium, share prices would be expected to rise by approximately 9 per cent. With 10 years of observations after the change in the premium, the upward bias to the measured equity premium would be 0.9 percentage points – almost the same as the size of the change that the empirical test would be trying to detect. Even with 20 years of observations used after the change in the premium, the upward bias to the measured equity premium would be 0.45 percentage points – almost half of the size of the change in the underlying equity premium.

584 Draft Decision, p.17. While the 'augmented Dickey-Fuller' test presented by Envestra was taken into account, it was not commented upon expressly in the Draft Decision. This test, and the results presented by Envestra, are considered further below.

Alternative estimates of the historically expected equity premium

The Commission also made reference to a number of recent studies from the US that have used alternatives to actual share market returns to impute the returns that investors actually expected (rather than received) over this period.

In general terms, these studies noted that the expected return to shares could be expressed as the sum of the expected yield and the expected capital gain. Long term estimates of the equity premium implicitly use actual yields and actual capital gains to estimate the expected returns. However, a central concern with these studies was that a range of unexpected events will cause share prices to rise (or fall) against that expected – and that the resulting capital gains (or losses) can be sufficiently large to lead to actual returns differing substantially from expected returns, even if a large sample is used. Accordingly, these studies employed other proxies for the expected capital gain. The range of proxies for expected capital gains included dividend growth, earnings growth, GNP growth and the trend growth rate in the stock of productive assets.[585] The studies referred to by the Commission, and their results, are replicated in table C.4 below.

TABLE C.4
HISTORICALLY EXPECTED EQUITY PREMIUM

Study	Time Period	Results (Proxy for Capital Gain)
Fama and French (2002)	1872-2000	4.4% (dividend growth)
	1951-2000	3.8% (dividend growth)
	1951-2000	4.8% (earnings growth)
Jagannathan et al (2000)	1926-1999	4.3% (dividend growth)
	1926-1999	5.7% (GNP growth)
	1946-1999	3.0% (dividend growth)
	1946-1999	4.4% (GNP growth)

Sources: Fama, E. and K. French, 2002, 'The Equity Premium', *The Journal of Finance*, Vol LVII, no. 2, p. 641, table 1 and pp 654-655, and table 4;[586] Jagannathan, R, E. McGrattan and A. Scherbina, 'The Declining U.S Equity Premium', *Federal Reserve Bank of Minneapolis Quarterly Review*, vol 24, no 4, tables 3 and 4.[587] The estimates are arithmetic averages of historical expected stock yields. The Fama and French results report the premium against (6 month) bills, whereas Jagannathan et al present the premium against bonds.

585 The more important of these studies was Fama, E. and K. French, The Equity Premium, *The Journal of Finance*, Vol LVII, no. 2, 2002.

586 The authors noted that adding the arithmetic averages of annual dividend yield and dividend or earnings growth would lead to a downward biased proxy for capital gain. The figures in the above table have been adjusted to remove this bias, using the method proposed by the authors.

587 The values presented are for the Centre for Research in Security Prices index.

Fama and French (2002) were careful to point out that their study was not an attempt to forecast the expected equity premium at a point in time based upon prevailing dividend yields and forecasts of dividend growth, or one that attempts to forecast point-in-time expected equity returns from other variables (that is, it is not an *ex ante* study). Rather, their study assumed that the stock return was stationary, and their estimates are of the average (unconditional) expected stock return. A common finding in these studies was that the historical equity premium measured using this approach was lower than that measured using actual returns,[588] particularly in the post World War II period.[589]

The Commission noted its understanding that there had not been any comprehensive studies similar to those quoted above, nor studies on the implications for the equity premium of accounting variables like returns on book value and book-to-market ratios undertaken for Australia. However, it was noted that the *ex ante* estimate of the equity premium that Professor Gray included in his submission on behalf of the distributors could be interpreted as an alternative estimate of the historically expected return in the same vein as the studies quoted above, with GDP growth used as the proxy for expected capital gains. The point estimate provided by this method was approximately 6 per cent (inclusive of franking credits) over the 1990s, although it was noted that this estimate had a large standard error.[590]

Surveys of opinions or assumptions

In the Draft Decision, the Commission noted that another methodology that has become a popular means of obtaining an estimate of the equity premium is to survey either experts or practitioners on the assumptions that they adopt with respect to the equity premium. It noted that regulators overseas have placed weight on these types of surveys when estimating the equity premium as an input in the CAPM.[591] Table C.5 shows the results of the three surveys from the US that were taken into account in the Draft Decision.

---

588 A third study was referred to that explained some of the unexpected capital gain in US share prices to a fall in the effective rate of taxation. In particular, it was found that the fall in the effective rate of taxation between 1960 and 2000 was predicted to result in an unexpected *doubling* of the value of corporate equity, in turn implying an upwards bias to the *arithmetic average* premium over this 40 year period of about 2.5 per cent per annum: McGrattan, E., Prescott, E., Taxes, Regulations and Asset Prices, NBER working paper no. 8623, 2001.

589 Fama, E. and K. French, The Equity Premium, *The Journal of Finance*, Vol LVII, no. 2, 2002, p.638. The authors also noted that there were a number of reasons to prefer their estimates of the expected equity premium over period between 1950 and 2000 to those provided by the historical average. These included that the estimates were more precise (lower standard errors), and that the average return from holding shares over the period exceeded the average return on investment of firms. If the actual returns to shares over the period reflected the expected return, the implication is that managers were undertaking numerous projects with a negative NPV – but which was difficult to reconcile with the average book-to-market ratio over the period of 0.66.

590 Gray, S, Issues in Cost of Capital Estimation, 19 October 2001, p.10.

591 For example, OFGEM referred to a number of surveys of various market practitioners in its recent decision on the price controls for Transco: Office of Gas and Electricity Markets, 2001, Review of Transco’s Price Controls from 2002: Draft Proposals, pp.153-154.

TABLE C.5

SURVEYS ON THE EQUITY

Study	Time of Survey	Surveyed Party	Responses	Equity Premium
Welch (2000)[a]	October 1997 and late 1998	Finance Academics	226	Mean: 7.1% Median: 7%
Welch (2001)[a]	August 2001	Finance Academics	510	Mean: 5.5% Median: 5.0%
Graham and Harvey (2001)[b]	June 2000-September 2001	Chief Financial Officers	1,116	4.2% [592]

a The equity premium reported is the 30 year arithmetic average equity premium measured against bonds.

b The equity premium reported is the 10 year arithmetic average equity premium measured against bonds.

Source: Welch, I, 2000, 'Views of Financial Economists on the Equity Premium and on Professional Controversies', *Journal of Business*, vol 73, no 4, pp. 501-537; Welch, I, 2001, The Equity Premium Consensus Forecasts Revisited, Cowles Foundation Discussion Paper No. 1325, Yale University; Graham, J., C. Harvey, 2001, Expectations of Equity Risk Premia, Volatility and Asymmetry from a Corporate Finance Perspective, working paper, Duke University.

The Commission addressed a number of concerns raised by Professor Gray about the reliability of the second (update) survey of US finance academics, but concluded that these arguments would not justify discounting the later results.[593] Indeed, the Commission noted that the latter survey had a number of desirable attributes – including that it had a much larger sample size, was more recent, and did not include information on the historical excess return to equity that may have affected responses to the first survey.

In addition, the Commission also had regard to the results of a survey of leading Australian academics and practitioners as reported by Professor Gray. The mean estimate of the equity premium from this survey was reported to be 5.87 per cent.[594]

Lastly, the Commission undertook its own additional research into the views of market participants. It commissioned Mercer Investment Consulting to provide advice on two matters namely:

- to advise on the assumptions that Mercer Investment Consulting use in its asset-allocation advice to institutional investors; and
- to report on the range of equity risk premia assumptions used by brokers and investment managers in security valuation.

The Commission noted that the second of these tasks was not intended to be a fully representative nor comprehensive survey of the assumptions adopted by Australian market practitioners, but rather intended only to provide some insight into the likely assumptions adopted by some key participants. That said, the Commission noted its view that Mercer Investment Consulting is well placed to advise on both of these matters.

592 The range for the equity premium of 3.6%-4.7% reported in the Draft Decision referred to the range for the average of responses across six separate surveys conducted between 6 June 2000 and 10 September 2001, and the number reported in the table above is the weighted average results from these surveys. A minor error in the number of responses reported in the Draft Decision has been remedied. The median of the expected equity premium was below the mean for all except one of the surveys.

593 Draft Decision, p.221.

594 Gray, S., Issues in Cost of Capital Estimation, 19 October 2002, pp.11-12.

Mercer Investment Consulting reported that the assumption about future equity returns it uses in their recommendations on the allocation of superannuation savings between stocks and bonds implies an equity premium of approximately 3 per cent (on the assumption that franking credits are not ascribed a market value) or 4 per cent (on the assumption that franking credits are valued). Regarding the views of brokers and investment managers it noted that there is no widespread agreement as yet on the size of the premium going forward, but that the majority of equity analysts and fund managers it surveyed employ assumptions lower than the long-term average of the historical premium to equities.

Conclusions reached in the Draft Decision

Having regard to the evidence considered (and summarised above), the Commission considered it appropriate to adopt an assumption about the equity premium that is lower than the point estimate provided by the long-term average of the historical equity premia, and adopted 6 per cent. It noted that this was the same assumption it adopted in the 1998 review.

C.4.3 Responses to Draft Decision

In their submissions on the Draft Decision, TXU and Multinet commented that they considered the equity premium to be 'at least 6 per cent',[595] whereas Envestra commented that 7.3 per cent should be used.[596]

All of the distributors appeared to assume that the Commission's views on the opinions of market practitioners were based solely upon the views of Mercer Investment Consulting, and so was argued that as the views were based upon one participant, they should be accorded little weight.[597] It was also argued by TXU and Multinet that the Commission erroneously reinterpreted the views of 'some key participants' summarised by Mercer in its consideration of the evidence as the views of 'many market participants'.[598]

Envestra argued that the long-term average of the historical actual premium to equities should be used as the expected equity premium, that is, 7.3 per cent. It referred to the results of the augmented Dickey-Fuller test discussed above, and argued that the finding that historical equity premia are stationary implies that the simple average of historical returns is the best, unbiased estimate of the expected premium.[599] TXU and Multinet also referred to the results of the Dickey-Fuller as refuting the Commission's conclusion that the variability of share market returns makes it difficult to detect structural breaks in the expected equity premium.[600]

---

595 TXU, Response to the Draft Decision, Attachment D, p.14; Multinet, Response to the Draft Decision, p.69.

596 Envestra, Response to the Draft Decision, p.41.

597 TXU, Response to the Draft Decision, Appendix D, p.15; Multinet, Response to the Draft Decision, Appendix C, p.15; Envestra, Response to the Draft Decision, p.41.

598 TXU, Response to the Draft Decision, Appendix D, p.15; Multinet, Response to the Draft Decision, Appendix C, p.15.

599 Envestra, Response to the Draft Decision, pp.40-41.

600 TXU, Response to the Draft Decision, Appendix D, p.16; Multinet, Response to the Draft Decision, Appendix C, p.15.

The distributors also argued that the Commission's approach to deriving the expected equity premium is not conservative – and not consistent with its conservative approach to deriving the equity beta.[601] It also argued that if the Commission is using a truly segregated CAPM, then the most recent historical evidence should be ignored as being tainted by foreigners – which would deliver a higher equity premium.

Envestra also argued that other market practitioners hold the view that the forward-looking premium is around 7 per cent.[602]

Professor Gray also commented that no weight should be placed on advice from a single participant (Mercer Investment Consulting), as it fails the test of statistical precision. In addition, Gray commented that 'the long-term average provides the most reliable estimate of the equity premium' and that 'this is consistent with commercial practice'.[603]

In a subsequent submission, Envestra commented that the Commission should not 'afford any weight to Mercer's advice in the Draft Decision'.[604] The concerns it raised included the following:

- Mercer's advice should be caveated because it is not an investor, and Mercer (it was argued) acknowledged that 'asset consultants tend to produce estimates of the ERP that are lower than those used by actual investors'.[605] It was argued that the Commission is prepared to place weight on an adviser on asset allocation, but not on the views of managers.[606] Comments were made about the incentives facing superannuation trustees.
- Mercer does not use the CAPM as a matter of course, and the ex ante model employed by Mercer has been criticised as suffering from large standard errors, and Mercer did not explain in full the reasons for the assumptions adopted.[607]
- It did not consider it possible for Mercer to support the belief that 'a consensus of market participants' agree that the point estimate of the long term average of the equity premium overstates current expectations.[608]
- The Commission drew 'selectively' from the Mercer advice, ignoring its comments about the value of franking credits.[609]

---

601 Envestra, Response to the Draft Decision, p.41; TXU, Response to the Draft Decision, Appendix D, p.16; Multinet, Response to the Draft Decision, Appendix C, p.15.

602 Envestra, Response to the Draft Decision, p.41.

603 Gray, S., Response to the Draft Decision, p. 2.

604 Envestra, 2003 Access Arrangement Review – Market Risk Premium (MRP), 12 September 2002, p.4. Multinet provided a substantially similar response: Multinet, 2003 Access Arrangement Review – Market Risk Premium (MRP), 12 September 2002.

605 As noted below, Mercer did not make any reference to the views of actual investors. Indeed, the estimate of the equity premium used by Mercer is an estimate of the assumption adopted by 'actual investors'.

606 Envestra, 2003 Access Arrangement Review – Market Risk Premium (MRP), 12 September 2002, p.2.

607 Envestra, 2003 Access Arrangement Review – Market Risk Premium (MRP), 12 September 2002, p.3.

608 Envestra, 2003 Access Arrangement Review – Market Risk Premium (MRP), 12 September 2002, p.3.

609 Envestra, 2003 Access Arrangement Review – Market Risk Premium (MRP), 12 September 2002, p.3.

C.4.4 Further analysis

Matters raised in submissions

As noted above, the distributors appeared to assume in their submissions that the Commission's conclusions on the views of market participants were based solely on the work undertaken by Mercer Investment Consulting. However, this was not the case. In the Draft Decision, the Commission also took account of the three US surveys, as well as the Jardine Fleming Capital Markets Survey – the last of which covered 61 respondents in Australia (of which 35 were non-academics).[610] The Commission considers the combined sample size of these surveys – together with the views of others summarised by Mercer and Mercer's own views – to amount to 'many market participants' as the Commission stated in the Draft Decision.

The further issues raised in submissions related, for the most part, to two matters, which are:

- (at least for Envestra), the implications of the 'augmented Dickey-Fuller' test for the method that is used to derive the estimated of the expected equity premium; and
- the evidence that exists on the assumptions adopted by market practitioners with respect to the equity premium.

Regarding the implications of the 'augmented Dickey-Fuller' test, the Commission notes that Envestra appears to conclude that the results of this test imply that the long-term average of the historical premium to equity is the 'best unbiased estimate of the expected value of the equity premium',[611] which is incorrect. In particular, the 'augmented Dickey-Fuller' says nothing about the relative efficiency of different estimation methods for the equity premium, and so it says nothing about whether a long-term average is 'best'. As discussed above, the approach adopted by the Commission is consistent with an assumption that there has not been a 'structural break' in the equity premium or that the process generating equity premia is stationary. However, the Commission remains of the view that the use of additional information on the size of the equity premium will improve the efficiency of the estimate.[612]

Regarding the use of other evidence that the Commission has relied upon, all of the distributors have criticised the application of weight to the report by Mercer Investment Consulting. Having considered these comments, the Commission does not accept that it would be inconsistent with the performance of its statutory duties to place weight on this report.

610 Jardine Fleming Capital Partners Limited, The Equity Risk Premium – An Australian Perspective, Trinity Best Practice Committee, September 2001. The results of this survey are discussed in more detail below.

611 Envestra, Response to the Draft Decision, p.40.

612 Given this finding, it is unnecessary to address the other technical issues associated with this application of the 'augmented Dickey-Fuller' test.

First, the Commission was well aware of the typical relativities of the views on the equity premium across different market participants and academics – indeed, Mercer expressly drew attention to the typical differences in opinion in its advice to the Commission:

> There is no emerged consensus, yet we perceive that brokers and investment managers maintain relatively higher estimates of the ERP than academics, and some academics have higher estimates of the ERP than asset consultants.[613]

The Commission is also not concerned that Mercer does not use the CAPM nor estimate a market risk premium as a matter of course, or that Mercer uses a methodology that Professor Gray considers to suffer from large standard errors. Capital budgeting (and the CAPM) is only one of the tasks that require an assumption about the equity premium – advice on asset allocation (which is Mercer's core activity) also requires an assumption about future equity returns relative to bonds (and therefore the equity premium). Indeed, one of the reasons that the views of Mercer were sought was because it has no interest in the size of the equity premium that is adopted for regulatory purposes, but yet an assumption about future equity returns (and therefore the equity premium) as an integral input into the advice it provides on asset allocation. The advice provided to the Commission was not an opinion as to what the Commission should adopt for regulatory purposes, it was a statement of what Mercer employs for its own purposes.

Regarding the method that Mercer employs to derive its assumptions about future equity returns, irrespective of Professor Gray's concerns, Mercer *does* use an ex ante method to forecast future equity returns and the results of this method influences the advice it provides on asset allocation. – that is, the use of this approach is 'market practice'. Moreover, it is noted that the submission from Envestra quoted Alan Kohler from the Australian Financial Review as referring to Mercer Investment Consulting as 'the largest and most influential asset consultant'.[614]

As noted above, the views of Mercer Investment Consulting (both the assumptions it adopts itself, and its opinion about the assumptions adopted by others) were only one of the sources of evidence on 'market practice' the Commission relied upon. However, regarding Mercer's own assumptions, the Commission considers the fact that it was prepared to disclose publicly the assumptions it employs in its asset allocation advice, its significance amongst asset consultants and its lack of interest in the assumption adopted by the Commission justifies the application of weight to its views. Regarding Mercer's opinion that a consensus of market participants agrees that the expected equity premium is lower than historical excess returns, the Commission considers that Mercer's unique position, and lack of interest in the assumption about the equity premium that is adopted by the Commission, to justify placing weight on its views, together with the other available evidence.[615]

613 Mercer Investment Consulting, Victorian Essential Services Commission Australian Equity Risk Premium, 1 July 2002, p.7.

614 Alan Kohler writing in the Australian Financial Review, 'Super Heads Off Shore', 23 May 2002, p. 61, quoted in Envestra, 2003 Access Arrangement Review – Market Risk Premium (MRP), 12 September 2002, p.2.

615 The Commission does not consider that it has drawn selectively from the Mercer report. The estimate of the equity premium the Commission drew from the report was consistent with an assumption that the market values franking credits fully – and so is a conservative interpretation of Mercer's assumptions (given that the Commission has assumed that franking credits are only partly valued).

As noted above, the Commission also referred to the results of the Jardine Fleming Capital Markets Survey in the Draft Decision as summarised by Professor Gray, which was reported to provide an average across the responses of 5.87 per cent. The Commission has subsequently received a copy of the survey results, which show that the premium of 5.87 per cent related to the views on the premium expected in the past – the average of assumptions about the forward-looking equity premium was approximately 1 percentage point lower. Table C.6 sets out the results of the survey for the different classes of respondent. The survey also canvassed views about the equity premium in the US – these results are reported also for illustrative purposes.

TABLE C.6
RESULTS OF THE JARDINE FLEMING CAPITAL MARKETS SURVEY

		Australia		United States	
	Responses	Past	Expected	Past	Expected
Academics	26	6.30%	4.92%	6.72%	5.17%
Brokers	20	5.05%	4.50%	5.93%	4.68%
Asset Consultants / Trustees	4	6.67%	3.13%	5.67%	2.13%
Corporate Managers	11	6.05%	5.27%	5.78%	4.55%
Total	**61**	**5.87%**	**4.73%**	**6.26%**	**4.70%**

Source: Jardine Fleming Capital Partners Limited, The Equity Risk Premium – An Australian Perspective, Trinity Best Practice Committee, September 2001.

The Commission did not consider the information on the break-down of the survey results between the different classes of respondent, and the survey results on the expected equity returns prior to the Draft Decision. As a result, it is new information. The Commission is cognisant of the disperse beliefs across the survey participants reported, as well as the response rate to the survey (less than 50 per cent), which it has taken into account in assigning weight to these results. Subject to those caveats, it notes that some of the observations that may be made on these results are as follows.

- the average of each of the classes is lower than the long-term average of the historical excess returns to equity;
- the simple average of views about the future equity premium are lower than the views about the past for every class of survey participant, and thus lower still than the long-term average of the historical excess returns to equity;
- corporate managers have the highest expectations about the equity premium – but the average of expected future values is lower than the long-term average of the historical excess returns to equity; and
- the average of views across the asset consultants and superannuation trustees is very close to the views of Mercer Investment Consulting.[616]

616 The first two points also supports Mercer's opinion about the views of other market participants.

However, there is some uncertainty as to whether the expected equity premia quoted include the non-cash value of franking credits (which is required for consistency with the Commission's gamma assumption). The Commission has adopted a conservative approach in this Final Decision and assumed that these stated premia relate to cash returns only, which implies that approximately 0.7 percentage points needs to be added on to the figures quoted above. This would imply that the average expected equity premium across the corporate managers (the highest category) is approximately 6 per cent, while the lowest expected equity premium (asset consultants / trustees) is approximately 4 per cent, and the average is approximately 5.5 per cent.

Professor Gray commented that:

> In my view, the long-term historical average provides the most reliable estimate of the equity premium. I agree with the Commission that this evidence is the most important consideration in estimating the equity premium and note that the "Commission remains of the view that weight should be placed upon long-term historical returns". This is consistent with commercial practice and is the most robust and reliable estimation technique.[617]

The Commission considers that, while commercial practitioners may place weight on the long-term average of the historical excess returns to equity, the weight of evidence does not support a proposition that commercial practice is to rely exclusively on this evidence. Rather, on the basis of the evidence discussed above, the Commission considers that the weight of evidence suggests that commercial practice is to adopt an assumption about the expected equity premium that is lower than the long-term average of the historical excess returns to equity.

Envestra also commented that the Commission has not considered the advice of managers when considering the views of market practitioners.[618] The Commission does not accept this criticism. In the Draft Decision, the Commission considered a survey of the views of US chief financial officers on the size of the equity premium, the results of which were summarised above. This survey (which had a combined sample size of over 1000) showed that these managers assume an equity premium of approximately 4.2 per cent – well below the estimate of the expected equity premium provided by the long term average of the historical premium to equity in the US. In the Final Decision, the Commission has also considered the results of the sample of these managers included in the Jardine Fleming Capital Markets Survey, which was taken to be approximately 6 per cent.

Regarding the comparison with the method used to derive the equity beta, the Commission notes that its approach has been to use the best available information with respect to all of the inputs into its cost capital, which will imply differences in weight assigned to various sources of information across the parameters. Regarding the consistency of the Commission's assumption about the equity premium with its assumption about the value of franking credits, first, the Commission has been careful to ensure that the information on the equity premium it has taken into account is consistent with its view on the value of franking credits. It is also noted that the Commission has not assumed completely segregated capital markets, given that it has assumed that franking credits are only partly valued.

617 Gray, S, Response to the Draft Decision, p.2.

618 Envestra, 2003 Access Arrangement Review – Market Risk Premium (MRP), 12 September 2002, p.2.

Further analysis

The Commission has adopted an equity premium estimate of 6 per cent (and a gamma assumption of 0.50) in every regulatory decision it has made to date, including its 1998 decision on the gas access arrangements, and other Australian regulators have applied the same assumption almost universally.

It remains of the view that it should place weight on the estimate of the expected equity premium that is provided by the long-term average of the historical excess returns to equity, but that it is appropriate to take account of other information on the premium to refine this estimate.

The Commission has had regard to a range of other pieces of information on the magnitude of the expected equity premium, including:

- concerns with the use of a long-term average;
- other approaches for interpreting the historically-expected premium that do not rely on the use of actual share market returns (noting that little research using these methods has been undertaken in Australia); and
- information on the assumptions adopted by market participants or other interested parties (such as academics), which included the results of three US surveys and one Australian survey, as well as information contained in a report by Mercer Investment Consulting, as discussed above.

The Commission remains of the view that the weight of evidence discussed above provides a sound basis for adopting an estimate of the equity premium that is below the point estimate provided by the average of the historical premia, but which otherwise is within the range provided by historical returns, given the variability associated with this measure. Indeed, the evidence discussed above (including the new information received since the Draft Decision) would suggest that many market practitioners would adopt an assumption about the equity premium that is lower than the assumption of 6 per cent that the Commission has adopted in previous decisions and in the Draft Decision.

Having regard to the information presented in the Draft Decision, the further information and other matters discussed above, the Commission has remained of the view that 6 per cent for the equity premium (for an assumption of 0.5 for 'gamma') is appropriate. While such an assumption may be out of step with the assumptions now commonly adopted by market practitioners, the Commission does not consider this evidence to be sufficiently persuasive to revise its past assumption about the equity premium, particularly when weight is placed upon the long-term consequences of the Commission's decisions.

C.4.5 Conclusions

The Commission has adopted an expected equity premium of 6 per cent, which assumes an estimate of 'gamma' of 0.50.

C.5 Proxy beta

C.5.1 Background and distributors' proposals

As discussed above, the Commission considers that, as with all of the assumptions adopted in the estimation of the costs of capital associated with the distributors' regulated activities, primacy should be given to objective evidence from the capital markets where this is available. However, in its previous consultation papers and in the Draft Decision, the Commission noted that, at the time of the 1998 decision, there was little information available from the Australian capital markets that could assist the Commission to derive a proxy beta for the regulated activities of the Victorian gas distributors. In its 1998 decision, the Commission commented as follows:

> Notwithstanding the large volume of information, analysis and views now on the public record in relation to the beta value for the Victorian gas distribution businesses, there is very little if any objective market data currently available in Australia on which to base empirical estimates of this key parameter in the WACC estimation for those businesses.[619]

While the Commission noted that caution needed to be exercised in drawing estimates of equity betas from other countries, neither the distributors, nor the Commission and its advisers considered that much weight at all could be placed upon estimates of betas for comparable UK companies. In its report to the Commission, Macquarie Bank explained the reasons for this as follows:

> We note that we have not placed a great deal of weight upon the UK regional electricity companies ('RECs') for beta comparisons. The significant changes in debt structures subsequent to privatisation, the subsequent adjustment to the regulatory framework, and the series of acquisitions and mergers which saw most RECs consolidated into other entities make comparisons from the UK very difficult.[620]

Given the absence of reliable information from the capital markets, the Commission placed most weight upon the proxy beta that had been used in a decision by a UK regulator – which was the UK Monopolies and Mergers Commission in its 1996 report on Transco, the UK gas transmission provider.[621]

---

[619] Op. cit., 1998 Final Decision, p.75.

[620] Macquarie Risk Advisory Services Limited, *Weighted Average Cost of Capital for Victorian Gas Access Arrangements*, July 1998, p.18.

[621] Op. cit., 1998 Final Decision, p.75.

The Commission noted in its previous consultation papers and in the Draft Decision that, since the time of the 1998 decision, additional capital market information has become available that should be taken into account. This includes the listing of two additional energy utilities in Australia that now have sufficient history to permit the estimation of equity betas,[622] as well as a reduction of the merger and acquisition activity and other potential factors that were considered to have limited the reliability of beta estimates for the UK in 1998 have subsided.[623] Indeed, the Commission noted in its 1998 decision that it expected further information to become available on the level of systematic risk of the Victorian gas distributors.

> Finally, the Office expects that experience in the administration of the regulatory regime over the next 5 years will bring significant data to light in relation to the level of systematic risk of gas distribution in Victoria, and the valuation and management of diversifiable risk in that sector. This will enable these issues to be revisited in the context of the next regulatory price review in light of that improved market data and experience. [624]

When deriving a proxy beta from a sample of beta estimates for comparable entities, care must be taken to distinguish between *equity betas* and *asset betas*. As the degree of financial leverage will affect the equity beta – even if the degree of non-diversifiable risk associated with a particular activity is held constant – a failure to adjust for gearing differences may result to inappropriate inferences being drawn. In its consultation papers prior to the Draft Decision, the Commission proposed to apply the practice now standard amongst the Australian regulators of adjusting equity beta estimates into the equivalent beta on the assumption that the asset were wholly equity financed (an asset beta), and deriving a proxy beta based upon the estimated asset betas for the comparable entities.[625] The same process would then be applied in reverse to convert the proxy asset beta into a proxy equity beta. A specific form for the adjustment was proposed.[626]

---

622 These companies are Envestra (listed in August 1997) and United Energy (listed in May 1998). At the time of the Draft Decision, a third company had been in operation for sufficient time to permit an equity beta to be estimated, which is the Australian Pipeline Trust (listed in June 2000). In the Draft Decision, the Commission noted that it used 20 observations as the cut-off point for estimating an equity beta, which corresponds to the cut-off employed by the Australian Graduate School of Management Risk Management Service.

623 Op. cit., Consultation Paper No. 1, pp.58-59. However, while the Commission reported beta estimates for gas distributors or sufficiently comparable utilities as relevant from the US and UK (measured against their home markets), it did not place significant weight upon the beta estimates for foreign firms. This is discussed further below.

624 Op. cit., 1998 Final Decision, p.226.

625 As the average equity beta is one, the average asset beta will be less than one (currently between about 0.7 and 0.8). There is a further de-levering step that could be taken which is to remove the effects of the level of gearing associated with the market portfolio. The market average for the resulting ‘double un-geared’ asset beta is one. While ‘double un-geared’ asset betas feature in the academic literature, they are not commonly referred to in general practice.

626 Op. cit., Consultation Paper No. 1, pp.57-58.

The proxy equity betas proposed by the distributors in their access arrangement submissions were very similar – TXU and Multinet proposed the use of a proxy beta of 1.15, while Envestra proposed 1.16 (all assuming a gearing level of 60 per cent debt-to-assets). All of the distributors derived a proxy beta for their regulated activities by taking the arithmetic average of the asset betas estimated for a group of Australian entities considered sufficiently comparable to those activities (the asset betas were derived by adjusting the estimated equity beta using a de-levering equation, and all distributor 0.23). Beta estimates were obtained over the period to June 2000 and June 2001 from the Australian Graduate School of Management Risk Management Service.[627] Prior to applying the de-levering adjustment, the estimated equity betas the 'Blume' adjustment was applied to the raw beta estimates.[628]

The distributors also presented a number of qualitative arguments regarding the magnitude of a proxy beta. These included the implications of operating leverage for betas, an argument that the betas of entities subject to incentive regulation should exceed those of entities subject to rate of return regulation, and that the betas of gas distributors are higher than those of electricity distributors.

TXU and Multinet also drew attention to the proxy betas that Australian regulators have adopted in recent decisions, as well as recent trends in betas for gas and electricity companies in the US and UK. Lastly, all of the distributors drew attention to the statistical uncertainty associated with the estimation of equity and asset betas, and argued that a conservative approach should be adopted.

C.5.2 Draft Decision

In the Draft Decision, the Commission adopted a proxy equity beta of 1 (for a gearing level of 60 per cent debt-to-assets) for the regulated activities of the Victorian gas distributors. The Commission expressed concern with three aspects of the method employed by the distributors to derive their proxy betas, which were that:

- the set of Australian comparable entities the distributors used to the derive the proxy beta included a company the Commission did not consider sufficiently comparable to the regulated activities of a Victorian gas distributor;
- the application of the 'Blume adjustment' to the raw beta estimates was inappropriate (that is, raw betas should be used); and
- the latest empirical data should be used to estimate the proxy equity beta (at the time of the Draft Decision, the latest beta estimates produced by the Australian Graduate School of Management Risk Management Service were the March 2002 estimates).

---

627 The Australian Graduate School of Management Risk Management Service estimates betas using monthly observations over the greater of four years of a firm's trading history (with a minimum of 20 observations accepted). Accordingly, the June 2000 beta estimates used the four years of data to the end of June 2000, whereas the June 2001 beta estimates used the four years of data to the end of June 2001.

628 TXU subsequently clarified that it and Multinet had not applied the Blume adjustment in their submissions.

The Commission's reasons on these matters, its own findings of the empirical evidence on equity betas, other observations relevant to the derivation of a proxy beta and the other matters it relied upon in the Draft Decision in forming its preliminary view on an appropriate proxy equity beta are summarised below.

Comparable entities

The Commission expressed its view that the pool of comparable entities should be restricted to those for whom the provision of regulated energy infrastructure accounts for a large share of their overall activities. While the Commission noted it had previously used three of the four comparable entities that were proposed by the distributors and still considered these appropriate –being AGL, Envestra and United Energy – it concluded that the fourth – the Australian Infrastructure Fund (AIF) – should be excluded from the set of comparable entities. In particular, the Commission noted that while the AIF specialised in infrastructure assets, its interests in energy-related infrastructure were only small – approximately 12 per cent of its portfolio as at 30 June 2001.[629] Its other main interests were in airports (50 per cent), ports (14 per cent) and roads (20 per cent), the first two of which have been accepted by Australian regulators as having higher levels of systematic risk.[630]

At the time of the Draft Decision, there was one further entity that met the selection criteria outlined above and for which a beta estimate was available, which was the Australian Pipeline Trust.[631] Accordingly, the Commission included this company in the set of comparable entities to which it had regard.

The Commission also concluded that it was appropriate to take account of the betas for overseas firms (measured against their home share markets) as a secondary source of information, although noted that caution needs to be exercised in interpreting those estimates.[632] The Commission identified a group of nine US gas distributors for which gas distribution accounted for more than 80 per cent of their revenue. For UK firms, the available entities are more limited, and betas for nine entities were sampled, which were entities for which electricity distribution and transmission or water services accounted for the majority of their activities. However, as noted below little weight was placed on these estimates.[633]

---

629 Its interest in energy has fallen to approximately 11 per cent as at 30 June 2002: http://www.ausinfrastructure.com.au/aif/index.cfm?site_name=aif, accessed on 10 September 2002.

630 Draft Decision, pp.227-228. The shares of airports, ports and roads as at 30 June 2002 was 59 per cent, 13 per cent and 13 per cent, respectively (http://www.ausinfrastructure.com.au/aif/index.cfm?site_name=aif, accessed on 10 September 2002).

631 As noted in footnote 622, the Australian Graduate School of Management's Risk Management Service only produces beta estimates where there are more than 20 observations available. This cut-off was adopted for the purposes of the Draft Decision.

632 It was noted that an implicit assumption when using betas for foreign as proxies for Australian activities is that the strength of this relationship between, for example, US gas distributors and the US share market is approximately the same as the relationship between the returns to Australian gas distributors and the Australian share market, which may vary for a number of reasons: Draft Decision, p. 229.

633 TXU and Multinet proposed an adjustment to betas observed for foreign firms to make them suitable for Australian activities. The Commission concluded that the specific adjustment proposed – which was to gross-up the foreign beta according to the beta between the Australian and foreign market – was illogical and thus inappropriate: Draft Decision, p.230.

Adjustments to beta estimates

As noted above, all of the distributors proposed applying a version of the 'Blume' adjustment to the raw beta estimates derived for the comparable entities. The precise adjustment proposed was to use a beta that is a weighted average of the observed (raw beta) and 1, with the weights being 0.67 and 0.33, that is:

$$b^{Adjusted} = 0.67 b^{Raw} + 0.33$$

This adjustment is included in the output provided by a number of beta estimation services,[634] and is based upon two prior beliefs about betas:

- in the absence of any information, a reasonable prior belief is that the beta of a stock is one – being the market average beta; and
- empirically, betas tend to get closer to one over time.

The Commission concluded in the Draft Decision that neither of these reasons provided a sound reason for applying the Blume adjustment.

Regarding the first of the reasons for the Blume adjustment, the Commission noted that the use of the average beta across a group of comparable entities is an alternative and preferable means of reducing the statistical uncertainty associated with individual beta estimates. Regarding tendency of betas to regress towards one over time, the Commission acknowledged the empirical support for the phenomenon, and that it may be reasonable to allow for such tendencies when projecting forward the estimated equity beta for an actual entity. However, it was noted that this tendency has been attributed to the conscious behaviour of managers – such as by undertaking projects with less extreme risk characteristics or by manipulating capital structures. As the Commission's objective is to estimate the cost of capital for a *pure-play* regulated gas distributor for a *benchmark capital structure*, it concluded that it would be inappropriate to take account of such a tendency.[635]

Accordingly, the Commission had regard to raw beta estimates only in the Draft Decision.

Levering and de-levering

The Commission had proposed the basic formula for adjusting betas for financial leverage in its previous consultation papers, which was adopted by the distributors in the access arrangement submissions. This formula is as follows:

$$b_a = b_e \frac{E}{V} + b_d \frac{D}{V}$$

where $ß_a$ is the asset beta, $ß_d$ is the debt beta, $ß_e$ is the equity beta, and E/V and D/V are the shares of equity and debt in the financing of the asset, respectively.

634 Bloomberg and Merril Lynch both provide Blume-adjusted betas. The weights adopted by the distributors are consistent with those employed by Bloomberg, whereas the Merril Lynch service applies a slightly lower weight of 0.65 to the raw beta.

635 Draft Decision, pp.234-235.

The Commission noted that the assumption that is adopted about the debt beta (that is, the share of an asset's systematic risk that is borne by debt providers) would affect the asset beta that is estimated from a given set of equity beta estimates. However, it noted that this assumption is unlikely to have a substantial impact on the re-levered equity beta, provided that the same assumption is used when estimating an asset beta from equity betas as when re-levering an asset beta back into an equity beta (that is, consistency is exercised).

Notwithstanding its marginal importance, the Commission demonstrated an approach for obtaining a more accurate estimate of the debt beta by using empirical information on the extent of default risk embedded in corporate bonds (a default premium is not part of the expected return, and so should not be included in an estimate of the debt beta). This analysis led to the Commission adopting a range for the debt beta of between 0 and 0.18. As this matter was raised in submissions, it is discussed further below.

Consideration of the empirical evidence

In the Draft Decision, the Commission noted that it saw considerable merit in deriving a proxy beta that is based upon the latest estimates of betas for sufficiently comparable entities. The use of the latest estimates was considered objective and is a method that can be repeated across successive price reviews and industries. It is also unbiased, because while beta estimates (and the average beta across a group of comparable entities) inevitably will move over time, there is no means of testing which of the time periods provides the best beta estimate.

In the Draft Decision, the Commission accepted a proxy equity beta (for an assumption of 60 per cent gearing) of approximately 0.7 to be consistent with the most recent market evidence on the beta for the regulated activities of the Victorian gas distributors. This proxy equity beta was derived as the simple average of the estimate of the raw equity beta for the comparable Australian entities discussed above, adjusted for leverage. Notwithstanding its preference for using the latest data, the Commission also noted that while the average re-levered equity beta for its group of comparable entities had varied over the past few years, the average for the group had not exceeded 1. The Commission also had regard to a weighted average of the equity betas for Australian entities, where the weights assigned more weight to the more precise estimates. However, this form of averaging resulted in a much lower proxy beta than the simple average, and so did not justify a revision to the proxy beta.

The Commission also had regard to beta estimates for the comparable US and UK firms discussed above. These betas were also much lower than those obtained for the Australian firms, with the re-levered (for 60 per cent debt-to-assets) simple average of the beta estimates approximately 0.40 for the UK firms, and 0.2 for the US firms, but which was not accorded significant weight.[636]

In addition, the Commission had regard to three qualitative arguments that the distributors presented on the size of the proxy beta, which were:

636 Draft Decision, p.239.

- a model referred to as a ‘fundamental beta estimate’, which was a relationship between the asset beta and operating leverage;
- the differences in systematic risk between entities subject to a price cap and those subject to rate of return regulation; and
- the differences in systematic risk between gas and electricity distributors.

Regarding the implications of operating leverage, while the Commission noted that the decomposition of beta implied by the formula is valid given its assumptions, it did not consider that any weight could be accorded its results. In particular, it noted that it was sensitive to certain inputs – in particular, a revenue beta – which cannot be estimated or observed, and also questioned the reliability of using introspection to impute a revenue beta. It also noted that some of the assumption underlying the decomposition of an asset beta into a relationship to operating leverage may not hold in practice.[637]

Regarding the implications of the regulatory regime, the Commission noted that the implication of a difference in the systematic risk between price cap and rate of return regimes would be that asset betas estimates for the US firms should be adjusted upwards or accorded less weight when deriving a proxy beta for the Victorian gas distributors. However, it has no implications for betas sourced for Australian or UK firms. It was noted that the Commission considered this matter in its 1998 gas decision, and again in its recent determination of price controls for the electricity distributors, and has previously placed some weight on the theoretical and empirical arguments for this proposition. However, it has also noted a number of weaknesses in the arguments presented.[638] Accordingly, the Commission noted that it considered it appropriate to have regard to the betas from US firms, but the weight applied to them will be influenced by the previous arguments.[639]

Regarding the comment that gas has higher relative risk than electricity, the Commission noted that it was not convinced that the empirical research to which reference was made actually demonstrated that asset betas for gas distribution are higher than those for electricity distribution. It also noted that TXU’s opinion that gas has higher relative risk than electricity during the current review of price controls for its gas distribution business were in sharp contrast to the views it expressed during the Commission’s recent review of price controls for its electricity distribution business, where it stated that:

> In TXU’s view, there are no cogent reasons to conclude that the beta of Victorian electricity distribution assets should be lower than that of Victorian gas distribution assets.[640]

637 Draft Decision, p.240.

638 This matter was discussed at length in Op. cit., Electricity Distribution Price Determination 2001-05, Vol 1, pp.271-273.

639 Draft Decision, p.241. As little weight was placed on the betas from US firms, this observation was not of much significance for the conclusions reached in the Draft Decision.

640 TXU, Response to Consultation Paper No. 4: Cost of Capital Financing, Electricity Distribution Price Review, 1999, p.12.

The Commission noted that during its review of the price controls for the Victorian electricity distributors, it did not distinguish between the risk associated with the electricity and gas distribution activities of the Australian comparable entities, and it concluded such a distinction would not be practicable or well-founded for the review of the gas access arrangements.[641] As this matter was raised in submissions, the Commission's consideration of the empirical evidence is addressed further below.

In contrast, the Commission noted that one factor that is relevant for the interpretation of the asset betas estimated for the Australian proxy group is that two of the three companies have substantial interests outside of gas or electricity distribution, which would be expected to have higher levels of systematic risk than regulated gas distribution.[642] This matter is also discussed further below.

Lastly, the Commission also had regard to the proxy betas applied by regulators in relevant recent decisions. It was noted that while primacy should be placed upon objective market evidence, the Commission previously has placed weight upon other regulatory decisions – and, in the case of the Victorian electricity distributors, consideration of these decisions applied pressure for a higher proxy beta than otherwise.

The Commission concluded that while it saw considerable merit in deriving a proxy beta that is based upon the latest estimates of betas for sufficiently comparable entities, the beta that would follow from this – 0.7 – was substantially lower than that used in other regulatory decisions, including by the Commission itself. The Commission noted that in its most recent decision, it had noted a reluctance to move too far from the range of proxy betas that have been adopted in comparable regulatory decisions given the limited range of capital market information that currently exists.[643] While since that time, one further empirical beta estimate is available (the Australian Pipeline Trust), it noted that that estimate relied upon only 21 observations, and is correspondingly imprecise. Given the imprecision, the Commission noted that it was appropriate to exercise a conservative judgement. That said, the Commission noted that the recent empirical evidence, as well as the decisions of other regulators on comparable matters implied that a change to the proxy beta from that adopted in the 1998 review (of 1.2) was appropriate.

---

641 If the gas distributors' arguments were accepted, then the Commission should have adopted a lower proxy beta than it did when determining price controls for the Victorian electricity distributors.

642 The Commission noted that, in a recent submission to the Queensland Competition Authority, Envestra had referred to the Victorian gas market as 'arguably the lowest risk market for natural gas in Australia' (Envestra, Access Arrangement for the Queensland Distribution Network: Envestra Limited Response, 2001, p.34). However, the Commission noted that it was not convinced that the differences in risk necessarily related to differences in systematic risk, and so placed little weight on the observation: Draft Decision, p.242.

643 Op. cit., Electricity Distribution Price Determination 2001-05, Vol 1, p.283.

The Commission adopted a proxy equity beta of 1 for the Victorian gas distributors' regulated activities, for an assumed gearing level of 60 per cent. It emphasised that this estimate is well above that which would be derived exclusively with reference to the latest market data. That is, in deriving this proxy beta, the Commission placed *considerable weight* on the desirability of continuity between regulatory decisions, and the long-term consequences of the Commission's decisions for the Victorian gas industry. However, it noted that additional evidence from the capital markets should be available at future reviews, at which time the Commission envisaged placing far more weight on the latest empirical estimates than it did in the Draft Decision.

C.5.3 Responses to Draft Decision

All of the distributors contested the Commission's conclusion that the proxy beta adopted in the Draft Decision was conservative, arguing that this conclusion relies on the assumption that the empirical evidence to which the Commission had regard was reliable or statistically robust.[644] TXU and Multinet concluded on this issue as follows:[645]

> [TXU Networks / Multinet] would contest any suggestion that the Commission's decision on the equity beta is conservative. In [TXU Network's / Multinet's] view the Commission's Draft Decision could only be interpreted as conservative in the context of applying a high (and unjustified) degree of confidence to the most recent market data …

The distributors noted the challenges associated with obtaining reliable empirical beta estimates, and suggested that the recent behaviour of stock markets may imply that current estimates of betas are not representative of future betas. On the latter point, all three argued that 'the most recent market evidence includes a period that has involved an unprecedented boom in equity prices, followed by an equally unprecedented bust', which may affect the relevance of the measured equity betas over this period.[646]

TXU and Multinet noted that, when using US data, the Commission restricted itself to companies with minimal interests outside of gas distribution, whereas for Australia, its proxy group included companies with non-trivial non-distribution interests. They asked the Commission to explain the rationale for the different selection criteria for the US and Australia.[647]

All three distributors also reiterated their view that the evidence they referred to in their access arrangement submissions (and considered in the Draft Decision) implied that gas distributors have higher systematic risk than electricity distributors.[648]

644 Envestra, Response to the Draft Decision, p.42; TXU, Response to the Draft Decision, Attachment D, pp17-18; Multinet, Response to the Draft Decision, Attachment C, pp.16-17.

645 TXU, Response to the Draft Decision, Attachment D, p.18; Multinet, Response to the Draft Decision, Attachment C, p.17.

646 Envestra, Response to the Draft Decision, p.42; TXU, Response to the Draft Decision, Attachment D, p.17; Multinet, Response to the Draft Decision, Attachment C, p.16.

647 TXU, Response to the Draft Decision, Attachment D, pp.17-18; Multinet, Response to the Draft Decision, Attachment C, p.17.

648 Envestra, Response to the Draft Decision, p.43; TXU, Response to the Draft Decision, Attachment D, p.18; Multinet, Response to the Draft Decision, Attachment C, p.17.

Envestra also raised two technical issues, the first of which related to the Commission's assumption about the debt beta, and the second to the Commission's reference to a weighted average of betas (with the weights determined according to the precision of the estimate).[649] These comments were based upon a report prepared for Envestra by Ernst and Young.[650]

TXU and Multinet concluded that an equity beta of 1.15 should be assumed (implying an asset beta of 0.46 for an assumed debt beta of zero).[651] Envestra referred to its estimate of the equity beta presented in its access arrangement submission (of 1.16) and stated that '[t]here are no underlying reasons why this estimate does not represent an unbiased estimate of the expected value of the equity beta'.[652]

C.5.4 Further analysis

As noted above, in the Draft Decision, the Commission concluded that three aspects of the method used by the distributors to estimate empirical equity betas were inappropriate, which were that:

- the Australian Infrastructure Fund should be excluded from the set of comparable entities as it is not sufficiently comparable to the regulated activities of a Victorian gas distributor;[653]
- the 'Blume adjustment' should not be used, that is, regard should be had to raw beta estimates; and
- the latest empirical data should be used to estimate the proxy equity beta.

In their submissions to the Draft Decision, the distributors did not comment on the Commission's exclusion of the Australian Infrastructure Trust, or on the appropriateness of the 'Blume' adjustment. Accordingly, the Commission confirms the conclusions it reached in the Draft Decision on these matters for the reasons summarised above and set out in more detail in the Draft Decision.[654]

649 Envestra, Response to the Draft Decision, pp.43-45.

650 Ernst and Young, Cost of Capital Beta and Debt Margin Issues, 7 August 2002.

651 TXU, Response to the Draft Decision, Attachment D, p.18; Multinet, Response to the Draft Decision, Attachment D, p.17.

652 Envestra, Response to the Draft Decision, p.47.

653 There is a further complication with the use of the Australian Infrastructure Fund (AIF) as a comparable entity that the Commission did not discuss in the Draft Decision. The level of gearing the distributors have assumed for the AIF reflected the level of debt against the AIF. However, the assets the AIF holds, in most cases, are equity investments in entities that have debt themselves (some of which, such as Epic Energy, have very high levels of gearing). The level of gearing employed to estimate an average asset beta for the activities the AIF has invested in should reflect both the gearing against the AIF as well as the gearing of the entities in which it has invested. The implication is that the method employed by the distributors may have overstated substantially the re-levered equity beta implied by the AIF equity beta.

654 Draft Decision, pp.227-228, 234-235.

At the outset, it is noted that if adjustments are made for these two matters, then the distributors' own analyses presented as part of their access arrangement submissions would not provide any support for the proposition that the Commission has understated the equity beta associated with their regulated activities. The distributors' proposals were based on the simple average of re-levered equity betas for their proxy group using the June 2000 and June 2001 Australian Graduate School of Management Risk Management Service estimates. Table C.7 shows the range the distributors would have quoted had the Australian Infrastructure Fund not been included in the set of comparable entities and the 'Blume adjustment' (for Envestra) not been applied.

TABLE C.7
DISTRIBUTORS' EQUITY BETA ESTIMATES – ADJUSTED FOR THE DRAFT DECISION

	Distributor's Proposals – Unadjusted		Distributor's Proposals – Adjusted	
	Debt Beta = 0	*Debt Beta = 0.23*	*Debt Beta = 0*	*Debt Beta = 0.23*
June 2000	1.24 / 1.28	1.16 / 1.20	0.91	0.74
June 2001	1.02 / 1.13	0.94 / 1.05	0.88	0.72

All of the entries are equity betas adjusted to be consistent with gearing of 60 per cent debt-to assets.

The first beta estimate in each cell is that provided by TXU and Multinet, and the second is that provided by Envestra.

While it is not exactly clear how the distributors translated the empirical beta estimates into their proposed proxy betas, their proposals were drawn from within the range of the average betas at these two time intervals.[655] Accordingly, the Commission does not agree with Envestra's conclusion that there were no underlying reasons as to why its original beta estimate is not an unbiased estimate of a proxy beta of a regulated Victorian gas distributor. That is, merely adjusting for the two factors discussed above would permit this inference.

The Commission also disagrees with the suggestion of the distributors that the Commission has not taken account of the uncertainty associated with the estimation of equity betas, and that this uncertainty implies that the Commission's proxy beta cannot be held to be conservative. The Commission was aware of the uncertainty associated with the derivation of a proxy beta for the gas distributors' regulated activities, which was evidenced in its consideration of the matter in the Draft Decision.[656] However, it was precisely because of this uncertainty that the Commission considered it appropriate to adopt a conservative approach, and not adopt the value that it would have adopted had it placed sole weight on the latest empirical information (which would have implied a proxy beta of 0.7). That is, the presence of uncertainty does not imply the Commission has not been conservative – rather, it

655 Envestra's proposed proxy beta was approximately consistent with a simple average of the four entries set out in the table above. After making the adjustments discussed above, the simple average of each of the beta estimates is 0.81.

656 Draft Decision, pp.243-244.

On the matter of the reliability of the most recent empirical information on betas for utilities, the distributors suggested that there has been an 'unprecedented boom in equity prices, followed by and equally unprecedented bust', which may have caused measured equity betas to fall, and understate the forward-looking expected beta. However, the Commission notes that while there have been significant movements in share markets overseas over recent years (most notably the US), it is not clear that the movements in the Australian share market (which is relevant for the betas of Australian firms) were unprecedented. Indeed, in a recent speech, the Governor of the Reserve Bank of Australia appeared to conclude the opposite.[657]

> I want to stress that these risks come from international markets, not the domestic ones. Even though Australian share prices have fallen, compared with others they have done so by a smaller amount, from a much lower peak, and the fall has been much more recent. Most importantly, we did not have a "bubble" in our stock market as Diagram 1 attests. Nor have we had anywhere near the widening of credit spreads in debt markets that has occurred in the United States (Diagram 2). Our business environment has not been without incident, as several prominent failures show, but with the exception of One.Tel, they have not been the result of a boom and bust in the share markets.

The diagram that he referred to on equity prices (Diagram 1) showed that the growth in share prices in Australia approximately tracked the growth in corporate profits between 1990 and 2002, whereas US share prices more than doubled between 1996 and 2000, over which time corporate profits actually fell. Accordingly, the Commission is not convinced that the recent share market activity in Australia implies that recent beta estimates for utilities are likely to be biased.

The other issues raised in submissions concerned the Commission's selection of the group of Australian comparable entities compared to those in the US, the relative risk of gas versus electricity distribution, and the two technical issues raised by Envestra (debt betas and the weighted averaging approach referred to by the Commission). These are discussed in turn, followed by the Commission's further consideration of the evidence.

Comparable entities and gas versus electricity

As noted above, the Commission restricted its set of Australian comparable entities to those for whom the provision of regulated energy infrastructure accounted for a large share of their overall activities, although some of the comparable entities undertook substantial unregulated activities. In contrast, for the US entities, it restricted its sample to those for which regulated gas distribution alone accounted for a substantial share of its activities. The reason why the more restrictive criteria could be employed for the US firms was because there are many more listed gas distribution entities in the US, and a sufficient number of entities existed that met the tighter criteria.

---

657 Macfarlane, I, What Does Good Monetary Policy Look Like?, 12th Colin Clark Memorial Lecture, 21 August 2002, (available at: http://www.rba.gov.au/Speeches/sp_gov_210802.html. accessed on 11 September 2002).

As noted in the Draft Decision and above, the application of the looser criteria for Australian firms implies that the set of comparable entities includes entities that have substantial activities outside of regulated energy distribution. For example AGL has interests, amongst other things, in electricity and gas retailing, both of which would be expected to have higher levels of systematic risk. United Energy also had interests in gas and electricity retailing for much of the period over which the equity betas were estimated, and had a significant interest in telecommunications for some of the period. The Commission considers that these activities are likely to have a higher level of systematic risk than regulated distribution activities, and so the use of equity betas for these firms implies that the empirical betas derived are likely to overstate the systematic risk of a regulated Victorian gas distributor.[658]

Regarding the level of systematic risk of gas compared to electricity, it should be noted at the outset that the relevant question is the extent to which the activities of the comparable entities reflect those of the regulated Victorian gas distributors. It is noted that gas distribution accounts for a large share of the distribution activities of the entities, and so it is not clear that the question of the relative risk of gas against electricity is directly relevant. Moreover, as noted above, the inclusion of entities that undertake substantial unregulated activities implies that the betas observed for these entities are likely to overstate the beta of a gas or electricity distributor.

The Commission discussed the empirical evidence referred to by the distributors for the difference between the betas of gas and electricity distribution in the Draft Decision, and concluded that it was not convinced the empirical evidence demonstrated the distributors' proposition.[659] Some of the Commission's concerns include the following.

- the paper shows the average asset beta for the electricity distributors subject to CPI-X regulation is 0.57, whereas the average asset beta for gas distributors subject to CPI-X regulation is 0.84. However, while the sample of electricity distributors included the estimates for 18 firms, the sample of gas distributors included only one. Moreover, that firm was British Gas which, at the time, was vertically integrated and had large upstream production interests.
- while the paper showed an average asset beta of 0.41 for the electricity distributors subject to 'discretionary' regimes and 0.57 for gas distributors subject to this form of regulation, there were only four firms in each sample, from which it is hard to draw inferences about betas. Moreover, the fact that none of the gas distributors sampled was in the same country as one of the electricity distributors implies that country differences cannot be ruled out.
- in contrast, for firms that are subject to rate of return regulation, the average asset beta was 0.35 for electricity distributors, but 0.20 for gas distributors, which was based on a sample of 14 electricity distributors and 12 gas distributors.

658 Draft Decision, p.242.

659 Draft Decision, p.241. The report referred to is: Alexander, I., C. Mayer, and H. Weeds, Regulatory Structure and Risk and Infrastructure Firms: An International Comparison, World Bank Policy Research Paper No. 1698, 1996.

As noted in the Draft Decision, as cross-country comparisons are difficult, the most robust test is of the difference in betas within a country. The only country for which this could be done with the results presented in this report is the US, for which there was a sample of 9 electricity distributors and 12 gas distributors. The average asset values for US electricity and gas distributors presented in the report were 0.30 and 0.20, respectively. However, the Commission remains of the view expressed in the Draft Decision that a distinction between the systematic risk associated with gas and electricity distribution is not practicable, and has not been assumed in this review.

Debt betas and averaging of betas

Envestra's comments on the Commission's assumption about the debt beta and the form of weighted average the Commission referred to drew heavily on the report provided to it from Ernst and Young (E&Y), and so reference is made to the latter report.

Regarding the debt beta, at the outset it needs to be borne in mind that a change to the debt beta from 0.18 (as the Commission used as its upper bound) to 0.23 (as advocated by E&Y) would have little effect on the proxy equity beta derived from a set of empirical observations. That is, provided the higher debt beta is used to derive the asset betas from the equity beta estimates, and to re-lever that asset beta into a proxy equity beta, as the Commission has emphasised previously.[660] Indeed, as demonstrated below, the use of a higher debt beta as advocated would lead to a *lower proxy equity beta* being derived from empirical observations.

The Commission noted in the Draft Decision that if the expected return on debt is known, then the debt beta can be estimated by reverse-engineering the CAPM, that is:[661]

$$E(R_d) = R_f + b_d(R_m - R_f) \Rightarrow b_d = \frac{E(R_d) - R_f}{R_m - R_f}$$

660 Draft Decision, p.232 and references to previous material in footnote 321. Envestra has noted a larger debt beta will imply a larger asset beta (Envestra, Response to the Draft Decision, p.47). This is correct – however, if a larger debt beta is used, then an asset beta will re-lever into a lower equity beta, and it is the equity beta that is the input into the CAPM. Envestra also curiously stated that the Commission did not reveal its assumed asset beta in the Draft Decision. This is incorrect – it noted that its assumed equity beta was equivalent to an asset beta of 0.40 if a zero debt beta was assumed, or 0.51 if an asset beta of 0.18 was assumed (Draft Decision, p.244).

661 Draft Decision, p.232.

The expectation notation was included to make it clear that the correct input into the above equation (which is the CAPM, just applied to debt) is not the *yield* on corporate debt, because that yield will normally include a premium for default. That is, the yield on corporate debt can be expressed to comprise at least the sum of the *expected return* and the *default premium* – and only the former is relevant to the CAPM. The Commission noted that if the default premium can be estimated, then the expected return can be estimated as the yield less then default premium. The Commission does not consider there to be anything controversial about this proposition. However, E&Y's analysis appeared to assume that the correct input into the above equation is the *yield* on corporate debt.[662] This is only correct if the debt is default free (so that the yield and expected return are the same), which would generally be incorrect.

In order to obtain an estimate of the default premium, the Commission referred to a recent study by Elton, Gruber, Agrawal and Mann.[663] E&Y criticised the use made of that study by the Commission; however, many of those criticisms appeared to reflect a misunderstanding of the information the Commission drew from that study, and so are largely irrelevant. In particular, the only use the Commission made of the study was as a source of estimates of the default premium on different credit ratings on corporate debt.

Thus, the only assumption made by the Commission was that the default premium (in absolute, not relative, terms) for US debt was the same as that for Australian debt (for the same credit rating).[664] The Commission remains of the view that this is appropriate given that the default premia were calculated using an option pricing model using default and recovery rates for Standard and Poors and Moody's credit ratings, and these credit ratings are directly comparable across countries. The Commission recognised in the Draft Decision that the risk premium derived for US bonds may not be applicable to Australia – and made no use of this information. The Commission's discussion of its use of this information is reproduced below.[665]

> Elton, Gruber, Agrawal and Mann have provided estimates of the breakdown of the yield on US corporate bonds of different credit ratings and terms into the default premium, risk premium and tax premium (the last factor has less significance for Australia). While the risk premia may differ across markets, it would be expected that the default premia would be the same in all markets (particularly given that the study makes use of Moody's and Standards and Poors credit ratings, which should provide a consistent indicator of default risk across any market).

---

662 Ernst and Young, Cost of Capital Beta and Debt Margin Issues, 7 August 2002, p.3.

663 Elton, E., M. Gruber, D. Agrawal, C. Mann, 'Explaining the Rate Spread on Corporate Bonds', *Journal of Finance*, Vol. LVI, No. 1, 2001, pp.247-277.

664 E&Y asserted that the Commission assumed that 'yields on corporate debt in the US and Australia are assumed to be similar with respect to their proportional disaggregation of default premium, risk premium and default premium' (p.4). This statement is incorrect. The Commission only assumed that the default premium – in absolute terms – was the same.

665 Draft Decision, p.232. The reference for the article referred to is: Elton, E., M. Gruber, D. Agrawal, C. Mann, 'Explaining the Rate Spread on Corporate Bonds', *Journal of Finance*, Vol. LVI, No. 1, 2001, pp.247-277.

The only comment that E&Y made about the default premia used by the Commission was that 'the assumption of risk neutrality provides a solution that is highly contingent on its input parameters', with those inputs being the assumed default and recovery rates. However, no reasons were advanced that the estimated default premia were biased, and no evidence was advanced that Australian corporate bonds are default free (which, as noted above, is the implicit assumption in E&Y's derivation of the debt beta).

Accordingly, the Commission does not consider that the comments from E&Y demonstrate any error in the approach taken in the Draft Decision. Since the Draft Decision, the yield on corporate bonds has increased. Thus, applying the same methodology to derive a debt beta as used in the Draft Decision would imply an upper bound for the debt beta of 0.23, and so a range for the debt beta of between 0 and 0.23 is adopted below. The debt beta that would be derived from the application of Envestra's preferred methodology would result in a debt beta of 0.27. The implications of this debt beta are illustrated also.

Regarding the form of weighting the Commission referred to in the Draft Decision, as noted above, the Commission placed little weight on these estimates in the Draft Decision, and so the comments again do not have direct implications for the conclusions reached in the Draft Decision. That aside, one of E&Y's criticisms of the form of weighting was that it would understate the variance of asset betas if there is a non-zero debt betas, which in turn may bias the weights employed. This point is accepted, and so further reference to this form of weighting is not included in this Final Decision.

E&Y also suggested that the use of simple averages may be inappropriate, and that a beta should be drawn from within an interquartile range, with judgement exercised. The Commission does not accept this point. The use of simple averages is objective and a widely practiced method of combining beta or cost of capital estimates for a set of comparable entities for regulatory purposes, and consistent with the method of averaging employed by the distributors in their access arrangement proposals.

Further consideration of the evidence

The estimates of equity betas the Commission presented in the Draft Decision, updated to reflect the more recent estimates, are set out in table C.8 below. Note that since the Draft Decision, there are now more than 20 observations available for AlintaGas, and so the set of comparable entities now includes five firms.[666]

[666] The Commission noted in the Draft Decision that it would rely upon the beta estimate for AlintaGas once it was available: Draft Decision, p.244.

TABLE C.8
EQUITY AND ASSET BETAS FOR AUSTRALIAN ENTITIES: MARCH 2002

	Equity Beta	Gearing	Equity Beta (ßd = 0)	Equity Beta (ßd = 0.23)	Equity Beta (ßd = 0.27)
AGL	0.36	36%	0.23	0.31	0.33
Envestra	0.59	77%	0.13	0.31	0.34
United Energy	0.25	46%	0.13	0.24	0.26
Australian Pipeline Trust	1.30	55%	0.59	0.71	0.74
AlintaGas	0.10	41%	0.06	0.15	0.17
Simple Average			0.23	0.35	0.37
Re-levered to 60% D/A			**0.57**	**0.52**	**0.51**

Source: Betas were obtained from the Risk Management Service of the Australian Graduate School of Management. The estimates include four years of observations, or the firm's trading history. Firms are only included where there are more than 20 observations. The beta estimate for the Australian Pipeline Trust is the 'thin trading' (Scholes-Williams) estimate, as the test statistic provided by the AGSM service suggested this form of bias may be significant. The standard errors for the estimates are: 0.33, 0.27, 0.44, 1.04 and 0.47, respectively.

Gearing is calculated as the average gearing level over the estimation period, using daily share price observations and assuming that debt levels move linearly between observations. Debt levels were taken from annual reports and ASIC filings.

In addition to the latest information referred to above, the Commission presented quarterly beta estimates for the set of comparable entities for the two years up to and including June 2002.[667] The simple average asset beta, and re-levered equity beta for a 60 per cent debt-to-assets ratio is shown in table C.9. As noted in the Draft Decision, the historical beta estimates do not amount to additional information, rather the only difference in the successive estimates is that a new quarter of observations (three) are included in the estimation process and for AGL, the last quarter of the observations is dropped off.[668]

667 The Commission found a minor error in the derivation of the gearing levels for Envestra and United Energy in the Draft Decision. The remedy of this error is responsible for the minor change to the estimates of the re-levered equity betas.

668 Indeed, as not all of the comparable entities were in existence for four years over this period, the most recent estimate includes more information than the historical estimates.

TABLE C.9
AVERAGE BETAS FOR AUSTRALIAN COMPARABLE ENTITIES

	Asset Beta (ßd = 0)	Equity Beta (60% D/A)	Asset Beta (ßd = 0.23)	Equity Beta (60% D/A)	Asset Beta (ßd = 0.27)	Equity Beta (60% D/A)
Sept 1999	0.41	**1.03**	0.52	**0.95**	0.54	**0.93**
Dec 1999	0.39	**0.97**	0.49	**0.89**	0.51	**0.88**
March 2000	0.32	**0.80**	0.43	**0.73**	0.45	**0.72**
June 2000	0.40	**0.99**	0.51	**0.92**	0.53	**0.91**
Sept 2000	0.40	**1.00**	0.51	**0.93**	0.53	**0.92**
Dec 2000	0.23	**0.57**	0.35	**0.52**	0.37	**0.52**
March 2001	0.40	**1.01**	0.52	**0.94**	0.54	**0.93**
June 2001	0.33	**0.82**	0.44	**0.76**	0.46	**0.75**
Sept 2001	0.24	**0.60**	0.36	**0.55**	0.38	**0.54**
Dec 2001	0.23	**0.57**	0.35	**0.52**	0.37	**0.52**
March 2002	0.27	**0.68**	0.40	**0.64**	0.42	**0.64**
June 2002	0.23	**0.57**	0.35	**0.52**	0.37	**0.51**

Source: Betas were obtained from the Risk Management Service of the Australian Graduate School of Management. The estimates include four years of observations, or the firm's trading history. Firms are only included where there are more than 20 observations.

Gearing is calculated as the average gearing level over the estimation period, using daily share price observations and assuming that debt levels move linearly between observations. Debt levels were taken from annual reports and ASIC filings.

The proxy group for September 1999 and December 1999 included AGL and Envestra only, between March 2000 and December 2001, the proxy group comprised AGL, Envestra and United Energy, March 2002 includes AGL, Envestra, United Energy and the Australian Pipeline Trust, and June 2002 includes AGL, Envestra, United Energy, the Australian Pipeline Trust and AlintaGas.

The Commission also relied upon the beta estimates adopted by other Australian regulators for gas and electricity entities in recent decisions. The proxy betas adopted by regulators in recent relevant decisions, as presented in the Draft Decision, are reproduced in table C.10.

TABLE C.10

PROXY BETAS USED BY AUSTRALIAN REGULATORS IN RELEVANT DECISIONS

Industry	Proxy Equity Beta (60% D/A)
Gas	
Envestra / Allgas - 2001 (QCA)	0.97
AGL - 2000 (IPART)	0.90-1.10
Albury Gas Company- 2000 (IPART)	0.90-1.10
AlintaGas – 2000 (OFFGAR)	1.08
Great Southern Networks - 1999 (IPART)	0.96-1.10
Multinet / Stratus / Westar - 1998 (ESC)	1.20
Electricity	
Qld Distributors - 2001 (QCA)	0.71
Vic Distributors - 2000 (ESC)	1.00
NSW Distributors - 1999 (IPART)	0.96

Sources: Queensland Competition Authority; October 2001; Final Decision – Proposed Access Arrangements for Gas Distribution Networks: Allgas Energy Limited & Envestra Limited; page 231; Independent Pricing & Regulatory Tribunal; June 2000 ; Final Decision :Access Arrangement for AGL Networks Limited; page 64; Independent Pricing & Regulatory Tribunal; Jan 2000; Access Arrangement Information for Albury Gas Company Limited; page 6; Office of Gas Access Regulation; June 2000; Final Decision – Access Arrangement Mid-West and South-West Gas Distribution System; AlintaGas; page Part A-17; Independent Pricing & Regulatory Tribunal; March 1999; Final Decision – Access Arrangement Great Southern Energy gas Networks Pty Limited; page 24; Office of the Regulator General; October 1998; Access Arrangements – Multinet Energy Pty Ltd Westar Gas Pty Ltd Stratus Gas Pty Ltd – Final Decision; page 10; Queensland Competition Authority; May 2001; Final Determination – Regulation of Electricity Distribution; page 98; Office of the Regulator General; September 2000; Final decision – Electricity Distribution Price Determination 2001-05 Volume I Statement of Purpose and Reasons; page 120; Independent Pricing & Regulatory Tribunal; December 1999; Final Determination – Regulation of NSW Electricity Distribution Networks; page 45.

The Commission remains of the view that there is considerable merit in deriving a proxy beta that is based upon the latest estimates of betas for sufficiently comparable entities. As noted in the Draft Decision, the use of the latest estimates is objective and can be repeated across successive price reviews and industries. It is also unbiased, because while beta estimates (and the average beta across a group of comparable entities) inevitably will move over time, there is no means of testing which of the time periods provides the best beta estimate. Applying these principles to the current review would imply using a proxy equity beta for the target level of gearing of approximately 0.55 (using the simple average).

However, as the Commission noted in the Draft Decision, the use of 0.55 as the proxy equity beta would imply adopting an assumption about this input that is substantially lower than that used in other regulatory decisions, including by the Commission itself. The Commission remains concerned with the limited amount of Australian capital market evidence that is currently available. While the addition of AlintaGas to the set of comparable entities implies a proxy group of five firms, the beta estimate for that firm has relied upon only 20 observations, while the beta estimate for the Australian Pipeline Trust has relied upon only 23 observations.[669] As the Commission noted in the Draft Decision, it is aware of the long-term consequences of its decisions, and the appropriateness of adopting a conservative approach where there is substantial uncertainty. As it did in the Draft Decision, the Commission considers that the derivation of the proxy is one of the matters upon which a conservative exercise of judgment is justified.

That said, the Commission remains of the view that the evidence from the capital markets indicates that a change to the proxy beta from that adopted in the 1998 review is appropriate. The Commission also notes that the assumption it adopted in 1998 is well in excess of the most comparable of the decisions by other regulators (namely, decisions in relation to gas and electricity distribution).

The Commission has retained the assumption about the proxy equity beta that was adopted in the Draft Decision, which was a proxy equity beta of 1 for the Victorian gas distributors' regulated activities, for an assumed gearing level of 60 per cent. This is approximately equivalent to an asset beta of 0.40 for a debt beta of zero, or 0.54 for a debt beta of 0.23. However, as the Commission emphasised in the Draft Decision, this estimate is well above that which would be derived exclusively with reference to the latest market data. That is, in deriving this proxy beta, the Commission has placed *considerable weight* on the desirability of continuity between regulatory decisions, and the long-term consequences of the Commission's decisions for the Victorian gas industry.

However, as the Commission noted in the Draft Decision, additional evidence from the capital markets should be available at future reviews of both the Victorian gas and electricity distributors. Barring mergers or other such activities, equity beta estimates for six comparable entities – AGL, Envestra, United Energy, Australian Pipeline Trust, AlintaGas and GasNet – using a full four years of observations will be available for all of these companies by the time of the 2008 gas access arrangement review. At that time, the Commission would envisage placing far more weight on the latest empirical estimates than it has at the current review.

C.5.5 Final conclusion

The Commission has adopted a proxy equity beta of 1 for an assumed financing structure of 60 per cent debt to assets to estimate the cost of capital associated with the distributors' regulated activities.

---

669 The beta estimate for the Australian Pipeline Trust is the 'Scholes Williams' beta estimate, as the test statistic suggested that thin trading bias may be significant. An implication is that the standard error of this beta estimate is extremely high – approximately 1 – which implies that the 95 per cent confidence interval for the estimate is approximately -1 to 3.

C.6 Financing assumptions

C.6.1 Background and distributors' proposals

In consultation papers prior to the Draft Decision, the Commission proposed adopting a benchmark for the financing arrangements of the distributors' regulated activities, consistent with all of its previous decisions and those of other regulators, rather than try to take account of their actual financing arrangements. For the assumed gearing level, it proposed again adopting the assumption of 60 per cent debt-to-assets.

Regarding the benchmark debt margin, the Commission noted that primary regard should be had to recent, objective market evidence. That said, it was noted that the assumption made about the current cost of borrowing is dependent on the assumptions made about the credit rating and average term of the distributor's portfolio debt, and the Commission invited the distributors to disclose the assumptions adopted on these matters.

The distributors all proposed the use of benchmark financing arrangements, and an assumed financing structure of 60 per cent debt to assets, consistent with the Commission's proposal. The distributors all proposed the same margin over the risk free rate of 1.65 per cent, which they stated was based upon financing quotes for BBB-rated entities.

C.6.2 Further analysis

Regarding the assumption about the benchmark gearing level, the Commission noted that the 60 per cent debt-to-asset assumption proposed by the distributors is now almost standard across Australia for energy utilities and consistent with industry practice amongst Australian energy utilities, and so adopted this assumption.

Regarding the benchmark credit rating for a distributor, the Commission noted that it considered that an assumption of a BBB credit rating would be likely to understate the credit rating that could be maintained by an efficient gas distributor. It noted that both Envestra and GasNet both have a BBB rating, but maintain a gearing level of 74 per cent and 69 per cent debt to assets respectively. It also noted that the value of assets used to calculate this gearing ratio was the *market value* of assets, and that their gearing levels expressed as a proportion of regulatory value would be even higher. On balance, the Commission considered that BBB+ credit rating would be a reasonable – and probably conservative – assumption for the purposes of deriving a benchmark debt cost. It noted that these assumptions were consistent with the Commission's recent decision on the price controls for the Victorian electricity distributors, as well as those adopted by the Queensland Competition Commission in its recent decision on the access arrangements for the Queensland gas distributors,[670] which Envestra has accepted in that context.[671]

[670] Queensland Competition Authority, Proposed Access Arrangements for Gas Distribution Networks: Allgas Energy Limited and Envestra Limited: Final Decision, 2001, pp.220-222.

[671] ibid., p.222.

Regarding the term of the debt, the Commission has previously used 10 years as the basis for its cost of debt benchmark, which the Commission noted was also likely to be conservative (noting that even regulated entities in past reviews have suggested that an assumption of a 5 year term would be a reasonable assumption).[672]

Given these assumptions about the benchmark credit rating and term of debt, the Commission noted that it considers there to be substantial merit in adopting a method of calculating a benchmark cost of debt that reflects current market evidence to the extent possible, is objective, and can easily be replicated from one decision to the next, as well as from one industry to the next. Consistent with this, the Commission calculated a benchmark debt margin by taking the average daily yields for corporate bonds of this credit rating and term, averaged over the same period during which it sampled interest rates to derive the risk free rate.

The actual yields the Commission used were obtained by the CBASpectrum service that is operated by the Commonwealth Bank. These yields are calculated from the prevailing yields of Australian corporate bonds, with statistical methods used to project a yield for each particular credit rating and term. The data source implied an estimate of the average margin against Commonwealth Government bonds over this period of 1.33 per cent.[673] The benchmark yields provided by the CBASpectrum service were checked against the yields for the gas company corporate bonds on issue, and no evidence was found that these benchmark yields either understated or overstated the yield applicable to gas distributors.[674] In the absence of proposals from the distributors, the Commission assumed establishment costs (annualised over the term of the issue) of 5 basis points, which implied an all-up benchmark for the cost of debt of 1.38 per cent, which the Commission rounded up to 1.4 per cent.

The Commission also used data from the Reserve Bank of Australia to explain the difference in debt margin assumptions to those adopted in its previous reviews. It noted that the increase over the assumed margin of 1.2 per cent in the 1998 decision reflected a substantially more conservative approach to deriving the benchmark cost of debt.

Lastly, the Commission also tested whether the current cost of borrowing in fixed rate nominal terms is within the range of the implied nominal returns to debt providers, given available forecasts of inflation, which it noted was unlikely to be the case.

C.6.3 Responses to Draft Decision

Regarding the assumed benchmark credit rating and term for debt, none of the distributors made a direct comment on these assumptions.

---

672 See, for example, CitiPower, 2001 Electricity Distribution Price Review: Submission to the Office of the Regulator-General, 1999, p.123.

673 This information was sourced from the CBASpectrum website, which is operated by Commonwealth Bank research (http://cbaspectrum.com).

674 TXU and Multinet had argued that gas companies would likely face an additional margin of 5 to 10 basis points over an electricity distributor. The Commission noted that as it had based its assumption about the cost of debt on the average yield bonds across the BBB+ credit rating, comparisons with electricity were no longer relevant.

Regarding the derivation of the *benchmark yield* on debt, the submissions from the distributors either offered or appeared to offer some support to the method adopted by the Commission. However, all of the distributors commented that the yield adopted is insufficient because the Commission:

> has adopted a new and non-transparent approach to establishing the debt margin that is not supported by the available evidence.[675]

TXU and Multinet commented further that while they do:

> not necessarily take issue with the approach proposed by the Commission, the decision-making that has supported the proposed approach is not made transparent.[676]

All of the distributors expressed a concern that the Commission had relied on the results of only one research house (the CBASpectrum service, operated by the Commonwealth Bank), which used one of (but only one) of the most common methods for estimating corporate bond yield curves. The distributors also pointed to statements from various other market practitioners about the prevailing yield on corporate bonds, all of which were higher than the margin adopted by the Commission.[677]

However, in a late submission Envestra adopted the Commission's proposal to use the CBASpectrum service (operated by the Commonwealth Bank) and assumption of a BBB+ rating and 10 year term to derive a benchmark cost of debt. It noted that the yield over the period it expected to be used to derive the risk free rate was 1.63 per cent.[678]

All of the distributors also pointed to weaknesses in the Reserve Bank of Australia data the Commission referred to in the Draft Decision to illustrate the changes in bond yields over the last few years.

Regarding non-margin establishment costs, all of the distributors also argued that the allowance assumed by the Commission for non-margin establishment costs was too low. TXU and Multinet referred to the decision of the Queensland Competition Authority that assumed establishment costs of the equivalent of 30 basis points. They also stated that the ACCC has previously assumed 50 basis points, and that a study by the Reserve Bank of Australia found that bank fees for 5 year small business loans were 60 basis points. Both considered that an allowance of 15 basis points is appropriate.[679]

---

675 Envestra, Response to the Draft Decision, p.48; TXU, Response to the Draft Decision, Attachment D, p.19; Multinet, Response to the Draft Decision, Attachment C, p.18.

676 TXU, Response to the Draft Decision, Attachment D, p.20; Multinet, Response to the Draft Decision, Attachment D, p.19.

677 TXU and Multinet also commented that their analysis of the yields obtained by the Commission implied a yield of 1.37 per cent rather than 1.33 per cent. The difference between yields can be explained by the yield on the Commonwealth security that was assumed. TXU and Multinet used the yield on the bond with the closest maturity to ten years, which only has a term to maturity of [insert], whereas the Commonwealth used an estimate of the yield for a bond with a term to maturity of exactly 10 years (a linear interpolation between the closest bonds was used). The Commission's approach is consistent with its assumption about the risk free rate.

678 Envestra, Summary Submission, 12 September 2002, p.15.

679 TXU, Response to the Draft Decision, Attachment D, p.22; Multinet, Response to the Draft Decision, Attachment C, pp.20-21.

Envestra noted that typical transactions costs for corporate bond issues are dealer placement and Austraclear fees. It recommended that a margin of 10 basis points be added. It also argued that a margin should be added to reflect the cost of swapping floating rates into fixed rates, which it argued would imply adding an additional 10-20 basis points. However, in a late submission, Envestra proposed including only the 10 basis points transactions costs.[680]

C.6.4 Further analysis

The Commission has adopted the benchmark gearing ratio of 60 per cent debt-to-assets as it did in the Draft Decision. Table C.11 shows that such a benchmark is consistent with observed gearing levels for listed Australian utilities.

TABLE C.11
GEARING LEVELS FOR LISTED AUSTRALIAN UTILITIES: DEBT / ASSETS

	Jun 1998	Dec 1998	Jun 1999	Dec 1999	Jun 2000	Dec 2000	Jun 2001	Dec 2001	Jun 2002
AGL	21%	24%	30%	39%	39%	35%	44%	43%	40%
Envestra	64%	78%	86%	74%	81%	78%	79%	76%	74%
United Energy	40%	60%	52%	55%	40%	31%	45%	48%	52%
Aust Pipeline Trust	-	-	-	-	-	54%	55%	55%	56%
GasNet	-	-	-	-	-	-	-	69%	69%
AtlintaGas	-	-	-	-	-	45%	45%	38%	35%

Source: ASIC filings, annual accounts, and ASX share price data. Market capitalisation at each point is taken as the average of the previous 20 trading days. Debt is defined as total debt less cash and loan note principal (in the case of firms with stapled securities).

None of the distributors commented directly on the Commission's assumption of a benchmark credit rating of BBB+ and debt with a 10 year term, and so these assumptions have been adopted for the purposes of this Final Decision. For the reasons summarised above and set out in more detail in the Draft Decision, the Commission remains of the view that the credit rating and term assumptions are conservative.

Regarding the method that is used to derive a benchmark yield consistent with the credit rating and term assumption noted above, the Commission notes that while the distributors raised questions with the method used by the Commission to derive the yield, there were no direct criticisms of the information source used, nor were any alternative sources proposed. The Commission considers that a particular advantage of the CBASpectrum data source is that it is readily accessible and used for purposes outside of a regulatory price review, and which would be appropriate to continue to use in the absence of any sound reasons to consider the benchmark yields it provides were biased.

680 Envestra, Summary Submission, 12 September 2002, p.15. The Commission notes that the yields from which it derived its benchmark cost of debt reflect fixed rate bonds, and so there is no requirement to enter into a swap to fix the interest rate. Thus, the inclusion of the swap cost would be inappropriate.

To this end, the Commission examined the indicative yields for corporate bonds from other market practitioners that were included in the material the distributors referred to. This analysis found that there was little difference between the CBASpectrum yields and the opinions expressed by the other market practitioners *when the yields are compared at the same point in time*. That is, the difference in the yields implied by the material submitted by the distributors and that used in the Draft Decision is due almost entirely to the point in time to which the opinion relates. Moreover, to the extent to which there were differences between the CBASpectrum yield and that obtained from different sources, the direction of the difference was not systematic. Accordingly, the Commission had adopted the same approach to that in the Draft Decision for deriving the benchmark yield.

The Commission also does not agree with the comment from the distributors that the approach for deriving the benchmark yield in the Draft Decision is new, or in any way non-transparent. The 1998 decision adopted a benchmark cost of debt – which implicitly was based upon an assumption about the credit rating and term of the debt – as the Commission has done in the current review. Indeed, the only change from the approach adopted in the 1998 decision and that adopted in the Draft Decision is that in the latter the Commission has stated transparently its assumption about the assumed credit rating and term of debt, and has derived the benchmark yield from a readily accessible source. Moreover, this change from the 1998 decision is unambiguously weighted in the distributors' favour. Had the Commission applied the same method to derive the benchmark yield in 1998, it would have derived a substantially higher margin (using information from CBASpectrum).[681]

The average CBASpectrum yield for 10 year bonds with a BBB+ credit rating over the same period in which the risk free rate was derived was 7.29 per cent, which implied a margin over the yield on Commonwealth Government securities of equivalent term was 1.63 per cent. While this yield is 30 basis points higher than the time of the Draft Decision, it is consistent with current market evidence, and so has been adopted in the Final Decision. The Commission notes that, as a number of the opinions on corporate bond yields presented by the distributors were substantially lower than this figure, the Commission's approach of transparently placing reliance on the latest market evidence has unambiguously benefited the distributors.

---

681 The Commission has not needed to refer to the Reserve Bank data series discussed in the Draft Decision again, and so has not addressed the concerns raised by the distributors. However, the distributors' comments that the corporate bond yields presented in the Draft Decision covered the A to AAA credit rating bands was incorrect. The data presented in the Draft Decision included only A rated bonds. It is also noted that, while the distributors discussed potential problems with the interpretation of the data presented, no actual evidence was presented to demonstrate that the information presented was misleading.

Regarding the margin on debt, the Commission is not persuaded to change from the 5 basis point allowance made in the Draft Decision. While the distributors have stated that an unbiased benchmark allowance would be higher, little in the way of evidence of this was presented. The Commission does not consider that TXU and Multinet's reference to Reserve Bank surveys of fees for small business loans provides any guidance about the non-margin establishment costs for the issuance of corporate bonds. It also does not consider the reference to the ACCC to be accurate – the ACCC appeared to assume 50 basis points in 'bank costs' for the purpose of calculating a debt beta, but did not appear to use this assumption in deriving the debt margin. The assumption adopted by the approach undertaken by the Queensland Competition Authority likewise does not appear to be informative – the allowance included for Envestra appeared to relate to its actual debt raising costs, which would have related to a much larger stock of debt than the stock of debt implied by the benchmark gearing assumption. Likewise, while Envestra has stated its views, no evidence to support its statements was presented.[682] In contrast, one of the pieces of advice on corporate bond yields that the distributors referred to stated the assumption adopted for the non-margin establishment costs, which was 5 basis points.[683]

Adding this allowance to the benchmark margin derived above implies a benchmark margin inclusive of fees of 1.68 per cent, which the Commission has rounded up to 1.7 per cent.

Lastly, as noted in section C.3 above, both TXU and Multinet argued that the Commission should test the implied nominal return to debt providers assumed against the current cost of borrowing in fixed rate nominal terms. The implied nominal return to debt providers can be calculated with the Fisher equation, using a forecast of inflation. Using the Reserve Bank target range of 2 per cent to 3 per cent, this implies a range of between 7.2 per cent and 8.3 per cent, or 7.7 per cent using the mid-point. Using the highest inflation forecast presented in section C.3 (from the Westpac/Melbourne Institute survey), the implied nominal return to debt holders is 9.7 per cent. The current nominal cost of borrowing in fixed rate nominal terms is just the benchmark margin plus the nominal bond rate, which is 7.4 per cent. Comparing the range of the implied nominal cost of debt with the equivalent benchmark in fixed rate nominal terms, the Commission does not consider that there is any evidence to suggest that there is a significant bias that the benchmark cost of debt would understate the cost of borrowing in fixed rate nominal terms – rather, if the mid-point of the Reserve Bank target range were used as the inflation forecast, then there is a weighting towards the distributors' interests of approximately 30 basis points.[684]

---

682 Envestra also did not state the term of the bonds to which the establishment cost related. As non-margin establishment costs are largely fixed, the cost as a proportion of the debt raised for longer term bonds will be lower.

683 Westpac, Letter to SPI PowerNet, 29 November 2001, included in: SPI PowerNet, Appendices to SPI PowerNet Revenue Cap Application for Period 1 January 2003 to 31 March 2008, Appendix F.

684 It is noted that had this test been undertaken at the last price review, the bias in favour of the distributors (using 2.5 per cent as the inflation forecast) would have been almost 50 basis points.

Notwithstanding this result, the Commission reiterates that for it to conclude that the benchmark assumption about the cost of debt were biased against the distributors (for example, because of the existence of an inflation risk premium, which raises the cost of fixed rate nominal finance), then all possible sources of bias would need to be examined. One of the matters that it would need to examine further is whether its assumption that distributors hold their entire debt portfolio in fixed rate nominal instruments with a ten-year term reflects standard or efficient practice. Another potential benchmark assumption is that the distributors hold a portfolio of debt of various maturities, as well as a portion of floating rate finance, and possibly a weighted average maturity across the portfolio of less than ten years.[685]

C.6.5 Conclusions

The Commission has assumed a benchmark gearing level of 60 per cent debt to assets and a margin for debt (inclusive of non-margin establishment costs) of 1.7 per cent over the 10 year real risk free benchmark.

C.7 Estimate of the cost of capital

C.7.1 Estimates and implied returns

Table C.12 provides the inputs the Commission has used to estimate the costs of capital associated with the distributors' regulated activities, alongside the equivalent assumptions adopted by the distributors in their proposed access arrangement revisions. The table also shows the equivalent parameters adopted by the Commission in its 1998 decision and in the Draft Decision.[686]

---

685 If an assumption were to be made that the efficient debt portfolio had a weighted average remaining life of 5 years, then the appropriate risk free rate would be the 5 year rather than 10 year rate (for the purposes of calculating the cost of debt only). At the time of this Draft Decision, the difference between 5 year and 10 year inflation indexed and nominal bonds was about 0.20 percentage points to 0.40 percentage points.

686 Multinet submitted that the Commission should not round-off the estimate of the after tax WACC to one decimal place as the Commission did in the Draft Decision. In the Draft Decision, it was noted that rounding to two decimal places would have favoured the distributors. The Commission does not accept the proposition that it is inappropriate to round-off its estimate of the cost of capital. Rather, given the uncertainty associated with estimates of the cost of capital, even rounding-off to the nearest 0.1 percentage point arguably implies a spurious level of precision. Accordingly, the Commission has continued its practice of rounding-off its estimate of the after tax WACC to the nearest 0.1 percentage point (one decimal place). It is noted that had it rounded-off its estimate to two decimal places (the nearest 0.01 percentage point) and applied to same rule to each of the inputs, then its the estimate of the after tax WACC would have been 6.77 per cent (that is, lower than the rounded-off value).

TABLE C.12
ESTIMATED COSTS OF CAPITAL ASSOCIATED WITH THE DISTRIBUTORS' REGULATED ACTIVITIES

	1998 Decision	Envestra (Vic & Alb)	Multinet	TXU	Draft Decision	Final Decision
Real risk free rate	3.41%	3.51%	3.50%	3.25%	3.50%	3.4%
Equity beta	1.2	1.16	1.15	1.15	1	1
Equity premium	6.0%	7.3%	7.0%	6.0%	6%	6%
Debt margin	1.2%	1.65%	1.65%	1.65%	1.4%	1.7%
Gearing (Debt/Assets)	60%	60%	60%	60%	60%	60%
Real 'Vanilla' WACC	**7.0%**	**7.9%**	**7.7%**	**7.0%**	**6.7%**	**6.8%**

As discussed in section C.1, the form of WACC adopted by the Commission is a real, after-tax WACC. The distributors receive compensation for inflation through being permitted to raise prices to reflect inflation during the regulatory period, and through adjustments to the value of their regulated assets for inflation at price reviews. An allowance for taxation (based upon benchmark assumptions about the tax status of the businesses, and an assumed value of franking credits) is included directly in the distributors' revenue benchmarks.

Given the Commission's inflation forecast, its estimate of the cost of capital associated with the distributors' regulated activities is consistent with a return to equity holders of 11.8 per cent and a nominal cost of debt of 7.4 per cent. The Commission considers that these returns are commensurate with prevailing conditions in the market for funds as the risk involve in delivering services in the Victorian gas distribution industry.[687]

687 It is noted that the distributors' submissions to the Draft Decision misinterpreted (and understated) the implied nominal returns to equity and debt providers that would be consistent with the Commission's input assumptions. In particular, for equity, the distributors calculated the implied nominal returns by calculating a nominal risk free rate and inserting that figure into the CAPM equation, and for debt, the distributors added the assumed debt margin to the nominal risk free rate. The Commission calculated its assumed real costs of equity and debt directly, and so the correct method for determining the implied nominal returns is to add on inflation to those real returns (using the Fisher transformation). The Commission's more recent approach of calculating the real costs of equity and debt directly is a change from the approach adopted in the 1998 Review.

However, it should be noted that comparing target nominal returns is potentially misleading where the regulated entity's revenues are linked to inflation (as under a CPI-X regime). The reference tariffs are expected to deliver an after-tax real return on equity of 9.4 per cent *plus outturn inflation*, and a real return to debt providers of 5.1 per cent *plus outturn inflation*. If inflation is higher (lower) than forecast, then higher (lower) nominal returns will be achieved – but real returns will be preserved. By way of example, if inflation were expected to average 2.5 per cent over the next regulatory period, then the implied returns to equity and debt providers would be 12.1 per cent and 7.7 per cent, respectively. In addition, these returns reflect only the assumptions that have been adopted to assess the distributors' reference tariffs. The actual returns to equity and debt providers will depend upon a whole range of factors, including each entity's financing decisions, and their ability to make efficiency improvements in excess of those assumed in the price controls.

C.7.2 Comparison of implied returns with other benchmarks

In their original and subsequent submissions, the distributors have urged the Commission to take into account other evidence on the cost of capital – such as the cost of equity – which provides evidence provided by 'market practice'. Similarly, customer groups have urged the Commission to take account of the views of regulators overseas, and provided a detailed benchmarking exercise to inform the Commission's decision-making.

In its previous consultation papers, the Commission outlined its views on the relevance (and therefore the weight that should apply to) other evidence on the returns required by investors.[688] It has drawn attention to the source of the difficulty with deriving the cost of capital, which is that the price of investment funds cannot be *observed*, but only *inferred* from the available capital market evidence. It has distinguished the cost of capital from the views of managers, which can also be distinguished from the views of investment advisers or other market practitioners or other regulators. These are *opinions*, not *estimates*. Finding objective evidence on required investor returns is not straightforward. The CAPM model uses capital market evidence to produce an estimate of required investor returns – and the difficulty associated with finding an alternative model is one of the reasons for its dominance in Australia, notwithstanding the criticisms that have been levelled at the model.

Notwithstanding, the Commission has noted that it would take into account evidence from 'market practice', as urged by the distributors, as a check on the results of its application of the CAPM.[689] The Commission is also open to consider the views of overseas regulators as suggested by customer groups. In addition, the Commission itself has referred to indicators of whether Australian regulators have been systematically biased in their decisions, either in favour of regulated utilities or customers, to which submitters have responded. These three sources of other evidence on the cost of capital associated with the distributors' regulated activities are discussed in turn.

688 Op. cit., Further Guidance to Gas Distributors, pp.35-37.

689 The Commission has taken account of evidence on 'market practice' where provided when deriving the various inputs into the CAPM, as discussed above.

Evidence from market practice

Notwithstanding the distributors' numerous comments that the Commission should have regard to 'market practice', the distributors or submitters on their behalf have provided very little in the way of credible information that would assist the Commission to obtain an unbiased view of the discount rates employed by market practitioners. The Commission is particularly concerned that the distributors or submitters on their behalf continue to refer to or produce opinions from parties that are produced for the sole purpose of a regulatory proceeding, are not accompanied with any evidence that those opinions are consistent with assumptions adopted in normal practice, and are provided by parties with a direct financial interest in the outcome.

In its original submission, Envestra referred to the views of two investment banks (Macquarie Bank and Toronto Dominion Bank) the views expressed by AMP Asset Management during the 1998 review of the distributors' access arrangements as evidence of 'market practice'.[690] KPMG (in a submission on behalf of the Australian Gas Association) also urged the Commission to have regard to market evidence on the returns required by the market. However, notwithstanding KPMG's assertions about the relevance of such market evidence and the 'failure by regulators' to take it into account,[691] the *only* 'market evidence' actually provided was a reference back to the opinions of three institutional investors that were expressed during the 1998 Review, being Axiom Funds Management, Hastings Funds Management and AMP Asset Management.

690 Envestra pointed to a number of pieces of 'anecdotal and empirical evidence' that it considered implied that the cost of equity for the regulated activities of a Victorian gas distributor is between 12 and 15 per cent. However, most of the material presented pertained to the returns required by investors from shares generally rather than from a regulated gas distributor, and so are more relevant to the equity premium, which was discussed above. Even so, it is not clear that Envestra has interpreted these pieces of evidence correctly. The study by Lonegran was attributed a value of between 12 and 15 per cent whereas Lonegran's assumption about the equity premium was 5 per cent (for a zero gamma value), which would imply a required return to equity lower than that assumed by the Commission (even if an adjustment were made for the value of franking credits). The Commonwealth Government capital usage charge was referred to and noted to be 12 per cent, whereas the current charge set by the Commonwealth Government (2002-03) is 11 per cent (although the Commission would find it difficult to place weight on this charge given that, at best, it would reflect the Commonwealth Government's view of the cost of capital associated with the activities undertaken by its agencies, and it may be designed also to achieve other objectives).

691 KPMG AGA sub, p.11. The Commission notes that KPMG's analysis may have been coloured by a basic misunderstanding of the nature of the CAPM. KPMG stated that the CAPM provides an estimate of the *minimum* rates of return that investors require. However, this statement is incorrect. The CAPM provides an estimate of the *expected (ie average)* return that investors would to invest in an asset, it does not provide an estimate of a *minimum* return.

Regarding the opinions of the two investment banks presented by Envestra, those opinions were expressed for the sole purposes of a submission to the Commission, were not supported by any analysis and did not include evidence that the opinions expressed were consistent with the assumptions they had adopted for purposes unrelated to a regulatory proceeding. In addition, both of these investment banks had had recent commercial relationships (or, in the case of one, an ongoing relationship) with Envestra.[692] Similarly, the opinions of the institutional investors who expressed opinions on the returns required by investors in 1998 were also expressed for the sole purpose of the regulatory proceeding, none provided any evidence that the opinions expressed were consistent with the assumptions actually adopted in their 'market practice' and all had significant interests in regulated utilities at the time of making its comments.

In light of these matters, the Commission considers that it should place commensurately less weight on the opinions referred to by Envestra or KPMG.

In contrast, the Commission considers it appropriate to place relatively greater weight on the views of market practitioners where those views were derived from decisions made, or advice provided, in the normal course of their 'market practice'. To this end, the Commission sought advice from Envestra about the assumptions that market practitioners make about the returns that investors require to hold its shares. Information was sought for Envestra because it is listed in Australia, and its activities relate almost solely to regulated gas distribution.

In particular, the Commission noted that Envestra had recently commissioned an independent valuation by Ernst and Young that disclosed its assumptions about the discount rate applicable to Envestra's cash flow. It also noted that it had received informal advice that the discount rates adopted by equity researchers for Envestra were materially lower than the cost of capital assumptions the Commission has adopted for Envestra's regulated Victorian activities. The Commission also noted that Envestra's statements that the cost of capital assumed in the Draft Decision understated its true cost of capital did not appear consistent with Envestra's public statements in either contexts. In particular, it referred to Envestra's statements that it will pursue acquisitions where it foresees a return in excess of eight per cent per annum after tax and where the price is less than one and a half times the regulatory value.[693]

Envestra's response to this request was as follows:

> We have considered your request again, but as foreshadowed by Andrew Staniford and Ian Little on 29 August 2002, we would not be comfortable in releasing the Ernst and Young report for the following reasons:
>
> it was prepared for internal accounting purposes only; it was not intended for any other purpose,

---

692 Macquarie Bank was joint lead manager of Envestra's indexed-bond and floating rate note issue in 2001 (Envestra, Envestra Victoria $250M CIBs and FRNs, media release, 26 June 2001) and undertook Envestra's $59 million equity placement earlier this year (Envestra, Envestra Completes $59 million Equity Placement, media release, 6 March 2002). Toronto Dominion refinanced part of Envestra's debt late last year (Envestra, Envestra – Successful $400 million Debt Re-finance, media release, 13 November 2001).

693 Envestra, Annual General Meeting: Chairman's Address, 5 November 2001.

> our Board of Directors has merely noted the report; it has **not** accepted or acted upon the recommendations made in the report,
>
> Ernst & Young have placed strict conditions on the use and confidentiality of the report.
>
> Given that our Board (as agent for the investors) has not adopted the Ernst & Young recommendations it follows that on balance, at this time, the report does not recommend a course which is necessarily in the best interests of investors. It is our judgment therefore, that the report is inappropriate for the purposes of the ESC.[694]

The Commission does not accept Envestra's response that regard to the Ernst and Young report is inappropriate, and questions the suggestion that the report was prepared for internal accounting purposes only and not for any other purpose. In contrast, Envestra announced the findings of the report in media release and stated that:

> Commenting on the report, Envestra's Managing Director, Mr Ollie Clark, said "Envestra's Board has yet to decide whether the Company would revalue its assets to reflect the revised values. However, the Board felt it necessary to ensure the market was aware of the conclusions of the report, particularly as the excess over current book value amounts to between 33.4 cents and 48.1 cents per stapled security currently on issue. Envestra's book value per security at 31 December 2001 was 64 cents.
>
> …
>
> Mr Clark concluded that Ernst & Young had clearly undertaken a comprehensive review of Envestra's business and related cashflow forecasts and the independent valuation should provide increased confidence to shareholders as to the value of their holdings in the Company.[695]

The principal inference that the Commission can draw from Envestra's reluctance to provide a copy of the report is that the cost of capital (discount rate) assumptions employed in the report were materially lower than that assumed by the Commission in the Draft Decision, when compared on a like-for-like basis. Regarding the opinions of equity analysts, Envestra stated that:

> Also it is our view that the analysts reports you requested are not relevant for the purposes of setting regulatory parameters. There is a high level of subjectivity employed in preparing analysts reports (reflected in a range of recommendations from buy to hold to sell) and as you have recognized a major input is the seemingly ever downward trend in regulatory WACC since the current regime was introduced. To use analysts' assumptions would be rather circular. It follows that the assumptions used in analysts reports are unsuitable for determining regulatory controls.[696]

---

694 Envestra, Re: Equity Analyst Research Report, 23 September 2002.

695 Envestra, Media Release: Independent Report Confirms Envestra's Network Business more than $200 million above book value, 4 March 2002.

696 Envestra, Re: Equity Analyst Research Report, 23 September 2002.

The Commission also does not accept that the views of analysts are not relevant as sources of advice on 'market practice', given that investors rely on the advice contained in these reports when deciding whether to buy or sell shares in Envestra. The Commission also does not accept that there is any circularity in having regard to the discount rates adopted by equity analysts, indeed, the Commission had addressed this point in its earlier letter:

> Upon reflection, I can understand why the assumptions that equity researchers employ to forecast future revenue (as an input into their cash flow forecast) would mirror the assumptions adopted by regulators. However, I would have thought that the discount rates employed by researchers to value the cash flow forecasts (and terminal value) would reflect the respective researcher's own assumption about the cost of capital associated with Envestra's activities, which need not be consistent with the assumptions adopted by regulators.[697]

The Commission infers that if the discount rates adopted by equity researchers for Envestra were higher than that assumed by the Commission in the Draft Decision, Envestra would have willingly provided these reports (on a confidential basis). Importantly, Envestra's response did not refute the Commission's informal advice that its assumption about Envestra's cost of capital is materially higher than the assumptions typically adopted by equity researchers (when compared on a like-for-like basis). Envestra's letter also did not refute the suggestion that its statements to the regulator about its cost of capital were inconsistent with its statements to investors about such matters.

There has been no evidence of a quality that the Commission could give significant weight during the course of the current review that would suggest that the Commission's assumption about the cost of capital associated with the distributors' regulated activities is lower that the discount rates typically used in 'market practice'. Specifically with respect to Envestra, the Commission sought patricular pieces of information the Commission considers would have disclosed assumptions adopted by market practitioners in circumstances unrelated to the current regulatory proceeding, and so could have been provided with significant weight by the Commission. However, Envestra denied the Commission's request.

Evidence from other regulators

As noted above, a submission on behalf of the Customer Energy Coalition (CEC) included a detailed benchmarking exercise of the cost of capital assumed by the Commission for the Victorian gas distributors' regulated activities against the returns assumed by regulators overseas in related matters.[698] The benchmarks produced in that submission suggested that the required returns assumed by Australian regulators (and the Commission itself) exceed by a large margin the required returns assumed by regulators overseas.

The distributors presented a combined response to the benchmarking exercise undertaken on behalf of the CEC, and their main criticisms included that:

---

697 Letter from G. Wilson (ESC) to A. Staniford (Envestra), 10 September 2002.
698 Pareto Associates, Customer Energy Coalition Response to the Draft Decision, August 2002.

- the evidence the Commission had regard to in its 1998 Review and the current review demonstrate that its decisions have not been generous compared to decisions in the US and UK;
- a NECG critique of a NERA report that compared returns assumed by regulators in the US and UK demonstrated that 'Australian regulatory decisions are not in any way generous in international terms';
- it is very difficult to attempt to benchmark returns across countries counties given that country specific factors may be present; and
- there is evidence that the returns in the UK water sector may be lower than investor requirements.

The Commission does not consider that the first of the criticisms above provides any reason to exclude consideration of the benchmarking analysis presented by the CEC. The Commission does not consider that the quality of information has been presented at either 1998 Review or the current review that would justify excluding from consideration the CEC benchmarking exercise. Rather, the Commission considers it desirable to have regard to any information that may provide further insight into required investor returns.

The Commission has also had regard to the NERA report that presented comparisons of returns assumed by regulators in Australia with the US and the UK, as well as the NECG critique of that energy report. One of NECG's comments was that the NERA report was selective and biased in the samples of firms that were compared, which the Commission does not consider to have any merit. Indeed, it is noted that the findings of the NERA benchmarking report were consistent with the results presented by the CEC.

The distributors also discussed a number of problems with attempts to benchmark returns between countries, some of which drew on the NECG work, noted above. The Commission accepts that some of these comments have validity, and has noted previously that required returns in one country could diverge substantially from required returns in another merely as a result of such factors as differences in the size and composition of the different share markets. The Commission also accepts that it is appropriate to make adjustments for differences in the 'risk free rates' between countries. The distributors also referred to evidence on the adequacy of the returns assumed by the UK water regulator in a recent price review, and comments that have been made about the impact of decisions by UK regulators on investment more generally, which is a relevant matter to take into account.

However, the Commission does not accept all of the criticisms made. For example, it does not accept that an adjustment for 'country specific risk' would be required in addition to an adjustment for differences in the risk free rate. The Commission has expressed its view previously that country specific risk would most likely be reflected in differences in the level of government interest rates in different countries.

However, while the Commission has accepted some of the criticisms made by the distributors of the CEC benchmarking exercise, it notes that none have attempted to adjust the CEC results for the problems identified and thus sought to provide a fair comparison of the returns assumed by regulators across countries. The Commission does not consider that the presence of 'pitfalls' in a benchmarking exercise is a sufficient reason not to undertake the exercise in the first place. In the absence of alternative benchmarking results presented by the distributors, the Commission does not consider it appropriate to dismiss the benchmarking results presented by the CEC, but rather will interpret and give weight to them, having regard to the distributors' comments.

Other objective market evidence

In its Draft Decision, the Commission observed that the market value of regulated utilities in Australia tends to be a multiple of their regulatory value, and suggested that this provided some evidence that, across the totality of the assumptions adopted when assessing price controls, Australian regulators are conservative.

Each of the distributors, together with KPMG (on behalf of the Australian Gas Association) responded to the Commission's comments on the relevance of the relationship between regulatory and market values. The thrust of the comments was that the appropriate comparator for the ratio of market-to-regulatory values was the Tobin's Q ratio for the economy as a whole. KPMG found that there was some empirical evidence to support the suggestion that market values have tended to exceed regulatory values. However, it appeared to conclude that there was no evidence that the ratio market and regulatory values for regulated businesses has exceeded the Tobin's Q for the economy as a whole.[699] It also discussed at some length the empirical issues associated with estimating Tobin's Q ratios.

The Commission is not convinced that the theory of 'Tobin's Q' provides the appropriate framework for interpreting the evidence provided by the market value of regulated assets, and notes that KPMG was incorrect in its statement that the Commission 'appears to rely on the Tobin's Q framework to … demonstrate conservatism'.[700] Tobin's Q framework was not mentioned in the Draft Decision.[701] The Commission's suggestion that comparison between the market and regulatory values for a particular activity may shed light on whether regulators tend to be conservative merely reflected the fact that such a result is implied by the method used to set regulated charges.

699 Australian Gas Association, Response to Draft Decision, August 2002, (prepared by KPMG), pp.36-37.

700 ibid., p.3.

701 KPMG referred to a discussion of Tobin's Q in a staff paper in 1998. The context for that discussion was a justification for permitting the applicant to use the DORC valuation methodology to set the regulatory values for the three distributors' assets. No mention was made of assessing the direction of bias in regulatory decision making.

As discussed in Appendix D, the setting of regulated charges involves, in effect, finding a price that would provide future cash flows with a market value equal to the regulatory value at the start of the regulatory period, given the regulator's assumptions about the cost of capital, future expenditure requirements, demand and other factors.[702] It necessarily follows that if all of the regulator's assumptions were unbiased forecasts, the market and regulatory values of the relevant asset would coincide exactly. Equally, the market value would only exceed the regulatory value if the net effect of all of the errors in the regulator's forecasts favoured the regulated entities. Indeed, the distributors would appear to have adopted the validity of this statement in their references to such comparisons being made in the UK. For example, a submission from the distributors included the following quote from Dr Keith Palmer, Vice President of Investment Banking and NM Rothschild and Sons:

> [The] equity market valuation of regulated assets is significantly lower than the regulatory asset value and has remained at a discount since the last price review. This discount has persisted despite industry performance broadly in line with the regulator's ex ante expectations. This is evidence that the expected return from holding regulated water assets is lower than the cost of equity to the sector. If this remains the case then the water industry will not be able to raise new equity in the future…[703]

However, the Commission is cognisant of some of the difficulties with obtaining direct comparisons between the market value and regulatory value of a particular activity, as well as the need to take care in interpreting those results. That said, the Commission considers that the results presented by KPMG, as well as the endorsement provided to the comparison of market and regulatory values that has been provided by well-credentialed UK observers, justifies a conclusion that the direct market evidence suggests that the decisions of Australian regulators have appeared systematically to favour regulated entities.

---

702 This interpretation of the process used to set regulated charges was set out clearly in the 1998 Decision: p.49.

703 Envestra, TXU and Multinet, Joint Submission: Response to the Customer Energy Coalition comments on the Cost of Capital, 6 September 2002, p.8.

C.7.3 Cost of raising equity

In a late submission, Multinet argued that the Commission should include an allowance in the revenue benchmarks for the cost of raising equity finance.[704] Multinet referred to a Draft Decision by the Australian Competition and Consumer Commission (ACCC) that had proposed to accept such an allowance in respect of GasNet.[705] No other Australian regulator, nor the ACCC in its previous decisions, has included such an allowance, and none of the distributors subject to the current review (including Multinet) had proposed the inclusion of such an allowance in their original proposals.[706] It would appear from Multinet's proposal that it had proposed that an allowance for the cost of raising equity apply to the whole of the assumed equity in its regulated activities (that is, 40 per cent of its capital base).

The issue of the treatment of the cost of raising equity is not straightforward and the Commission does not consider that comparisons with the cost of raising debt finance are appropriate. The Commission's benchmark assumption is that the distributors raise 10 year debt, which implies that debt instruments will be rolled-over periodically, and new debt issued and transactions costs incurred. In contrast, once equity finance has been raised, it is perpetual. In addition, transactions costs for equity only arise where new equity injections are required – no transactions costs arise where projects are financed from retained earnings and depreciation allowances.

Much of the current gas networks were in place at the time of the 1998 Review, having been installed – and therefore *financed* – over the previous decades. The Commission considers that, to the extent that there were transaction costs associated with the historical financing of those assets, those costs have been reflected in the values assigned to those existing assets by the Commission in its 1998 Review. While those businesses have since been privatised, this was a re-financing of existing assets, and the Commission does not consider it appropriate that transaction costs associated with that exercise be reflected in reference tariffs. Equally, the Commission does not consider it appropriate that the transaction costs associated with any future sales, reorganisations or similar changes be reflected in reference tariffs.

With respect to parts of the network installed after 1 January 1998, the situation is more complex. As noted above, transaction costs would only arise in situations where, under the benchmark financing assumptions adopted, new injections of equity were necessary. In turn, this requires assumptions to be made about the extent of the equity's share of new investment that can be financed from retained earnings and depreciation allowances (in turn requiring assumptions about the extent of earnings that an efficient firm would distribute to shareholders as dividends), which would be a relatively complex financial modelling exercise.

---

704 Multinet, Gas Access Arrangement Review: Matters Arising from the ACCC's GasNet Draft Decision, 6 September 2002.

705 Australian Competition and Consumer Commission, Draft Decision: Gas Net Australia Access Arrangement Revisions for the Principal Transmission System, 14 August 2002.

706 Multinet has referred to the similarities in approach between the ACCC and the Commission on finance matters, with the ACCC's treatment of equity raising costs in this recent Draft Decision a point of difference. However, another difference in approach is in the method used to derive the risk free rate. The ACCC has used yields on five-year bonds to derive a proxy for the risk free rate, whereas the Commission has used yields on ten-year bonds (resulting in a higher risk free rate than the ACCC would have determined). Multinet has not proposed that the Commission derive the risk free rate with reference to five-year bonds in order to be consistent with the ACCC on the determination of the risk free rate.

However, as the regulatory value of the networks as at 1 January 1998 were based upon replacement cost (thus implying large depreciation allowances) and modest rates of growth have been experienced and forecast, the Commission considers it unlikely that an efficient firm would have required new equity injections to meet capital expenditure requirements over the first or second regulatory periods. Importantly, even if an efficient business required new equity injections, then an allowance for transaction costs would be appropriate only in respect of the portion of capital expenditure that needs to be financed through that new injection.[707]

Accordingly, the Commission does not consider it appropriate to include an allowance for the transaction cost associated with raising equity in total revenue.

C.8 Assumption about company tax liabilities

As noted above, the model that has been used to estimate the required investor returns provides an estimate of the *after-tax* cost of capital. As the revenue benchmarks underpinning the new price controls will be defined in pre-tax terms, an assumption about the company taxation liabilities associated with sales of the regulated services over the regulatory period is inevitable.

A factor that is also relevant for the assumption about company taxation liabilities is that, under the system of dividend imputation, Australian shareholders are able to receive a credit for tax paid at the company level when determining their personal income tax. The standard practice amongst Australian regulators and finance practitioners is to treat this benefit as an offset to the particular entity's company taxation liability.

The assumed value of imputation (or franking) credits created is usually expressed as a proportion of their 'face value', with this proportion commonly denoted by gamma (γ). This approach implies that if a regulated entity were assumed to pay \$X in company tax in a particular year, then the regulated entity would only require an allowance of \$$(1-\gamma).X$ for taxation. The remaining $\gamma.X$ would be provided directly to shareholders through the imputation system.[708]

The discussion below first addresses the issues associated with the assumption about the company taxation liabilities associated with the delivery of the regulated services over the regulatory period. It then addresses separately the assumption about the extent to which this liability is offset by the operation of the imputation system in Australia.

---

707 If an allowance were made for the transaction costs of new equity injections, other complex issues may need to be addressed. For example, in Australia, the market value of regulated utilities typically trade at a multiple to the regulatory value. Assuming that new stock is sold at the market value, then external equity injections would provide a benefit to existing shareholders (that is, if \$100 million were injected and invested in the regulated activities, the market may value this at, say \$150 million, the remaining \$50 million flowing through to existing shareholders through a rise in the share price). Consistency may require that any such flow-on benefits from external equity injections also be taken into account.

708 This interpretation of the gamma term holds regardless of whether the value of franking credits are reflected in the WACC or in the cash-flows.

C.8.1 Benchmark for the cost of tax

Background and distributors proposals

In its consultation papers prior to the Draft Decision, the Commission expressed the view that providing an allowance for taxation that reflects an unbiased estimate of the taxation liabilities for an efficient company would best meet the requirements of the Gas Code. In these consultation papers, the Commission identified two broad approaches for deriving a benchmark assumption for taxation liabilities.

The first approach is to calculate the tax liabilities that would flow over the forthcoming regulatory period, given a set of explicit assumptions that are relevant to taxation. It noted that an implication of this approach is that the benchmark for taxation would reflect taxation liabilities over the forthcoming regulatory period only.

The second approach is to use one or more of the *simple transformations*, whereby the entity's company tax liability is assumed to be equal to the statutory tax rate, multiplied by a particular definition of income, with the definition of income that is used differing between the transformation methods. It noted that an implication of this approach is that the assumption that whichever of these methods is chosen provides an unbiased estimate of the *long-term* effective tax rate.

In these papers, the Commission expressed a number of concerns with using one of the simple transformation methods. One concern is that, as with any long-term effective tax rate, it is impossible to establish whether the allowance for tax is unbiased. This reflects the sensitivity to uncertain economic variables, and the potential commitment and incentive problems associated with the variation of actual taxation liabilities around the assumed long-term average value.

Another concern was that the assumptions about the taxation system implied by the simple transformation method are anything but obvious, thus precluding a transparent and informed debate about the allowance for tax provided. Lastly, the range of possible allowances implied by the alternative transformation methodologies that have been adopted is extremely wide and thus provides little guidance to regulators. The Commission noted its view that the inevitable result of this framework is that the allowance for tax is not underpinned by objective and reasoned analysis and cannot be explained with reference to other relevant factors, nor reconciled with the assumptions adopted about company taxation in other previous regulatory decisions, nor replicated across decisions and industries.[709]

In light of these concerns, the Commission proposed that the allowances for company taxation be derived as an explicit calculation of taxation liabilities. By explicit, the Commission meant that assumptions relevant to the tax position of the distributors would be specified, and the resultant taxation liability calculated.[710]

[709] Op. cit., Position Paper, p.43.
[710] Op. cit., Consultation Paper No. 1, p. 66.

In their submissions to these earlier consultation papers, the distributors unanimously opposed the Commission's proposal to derive a benchmark allowance for taxation as an explicit calculation of taxation liabilities. The distributors' principal concerns were that an actual calculation of tax liabilities would be overly complex and potentially create perverse incentives with respect to their tax-related decisions.[711]

In response to these concerns, the Commission made a number of proposals, which included to adopt simplifying assumptions for many of the inputs related to the benchmark tax calculation (that is, to reflect the major features of the tax law only, rather than all of its detail) and to adopt benchmark assumptions for the tax-related inputs to the extent possible.[712] It was noted that most of the assumptions required to estimate a taxation liability over the next regulatory period were required anyway – and that the only additional assumptions required related to tax depreciation. The Commission noted that industry-wide benchmarks could be used for some of the inputs required to calculate a tax depreciation allowance.

In their submissions accompanying their proposed Access Arrangement Revisions, the distributors all reaffirmed their preference for the use of one of the simple transformations discussed above to derive the allowance for company taxation. However, all three distributors derived the allowance for taxation included in their proposed reference tariffs by making an explicit calculation of the taxation liability, given a set of tax related assumptions.

The distributors adopted the assumptions proposed by the Commission for the non-depreciation items discussed above. Multinet and TXU stated that they used assumptions for tax depreciation that were consistent with that permitted by the tax law, whereas Envestra stated that it used 'effective life depreciation'. Envestra suggested that the use of 'effective life' depreciation rather than the depreciation permitted by the tax would provide an unbiased estimate of the cost of tax over the long term, and would avoid:[713]

- undermining the policy intent behind accelerated depreciation;
- retrospectively disadvantaging investors; and
- distorting the time path of reference tariffs.

Draft Decision

In the Draft Decision, the Commission reaffirmed its view that providing an allowance for taxation that is an unbiased estimate of the taxation liabilities for an efficient company would best meet the requirements of the Gas Code. The Commission considered the contrary arguments raised by Envestra, and commented as follows.

- *Undermining the policy intent behind accelerated depreciation* – it was noted that it is impossible to know whether or not the current tax depreciation rates actually provide a faster rate of depreciation than economic depreciation, as estimates of effective tax rates require (and are sensitive to) forecasts of

711 Op. cit., Position Paper, p.43.
712 ibid., p.44.
713 Envestra Ltd, Access Arrangement Information, pp. 35-36.

business and economic variables over very long timeframes. It was further noted that, even assuming the tax depreciation rates were ‘accelerated’, such measures only meet their objective of encouraging capital formation if the benefit from that tax saving is passed on to the users of the facility (thereby increasing demand for the relevant service provided by that facility);

- *Avoid retrospectively disadvantaging investors* – the Commission notes that its conclusion on the appropriate treatment of taxation is based upon its view about the approach that best meets the requirements of the Gas Code. In addition, the Commission was careful to signal its concern about the use of simple transformations in its 1998 decision; and
- *Avoid distorting the time profile of reference tariffs* – the Commission noted that there were other mechanisms to address concerns about the time profile of reference tariffs (in particular, a change to depreciation schedules).

The Commission also confirmed its previous view that the most appropriate means of deriving the allowance for company taxation is by making an explicit calculation of the company tax liability on the basis of a set of tax-related assumptions. As noted above, implicit in this methodology was that the allowance reflects the taxation expected in the next regulatory period.

The Commission noted that it does not believe that the calculation is complex, and that a reasonable benchmark for taxation can be derived with few inputs. It also noted that such an approach is more transparent, as changes in the allowance for taxation can be reconciled back to factors relevant to the tax law, or to changes in that law itself. It also dismissed the view that undertaking an explicit allowance for taxation would provide the businesses with material perverse incentives. Rather, it noted that it is straightforward to define industry-wide benchmarks for most of the inputs where the distributors would otherwise have discretion, based upon the decisions expected from a reasonably prudent business operating in line with standard industry practice.

Regarding the tax related assumptions adopted, those related to the non-depreciation elements of the benchmark tax calculation were as follows:

- Assessable revenue – assumed to be the revenue benchmark, including customer contributions;
- Operating expenditure – assumed to be the operating expenditure benchmark;
- Capital expenditure – taken as historical and forecast capital expenditure (noting that a portion of capital expenditure will be immediately deductible); and
- Interest deduction – taken as the nominal interest payments implied by the benchmark financing arrangements.

For the purpose of deriving a benchmark tax depreciation allowance, the Commission derived its own assumptions about the classes of assets that are relevant for taxation purposes, and the rates of depreciation that are applicable to each class. These classes of assets and applicable rates, and groups of assets, have been informed by the distributors' proposals, as well as by independent professional tax advice to the Commission. One of the assumptions (referred to in the distributors' submissions) was to adopt 20 years as the effective life of certain distribution assets from 1 July 2002, following the announcement to this effect by the Commonwealth Treasurer. The specific assumptions adopted are discussed in more detail below.

Responses to Draft Decision

In their responses to the Draft Decision, both Multinet and Envestra expressed concerns with the Commission's adoption of the 20 year effective life for new gas distribution infrastructure. Multinet urged the Commission:

> to recognise the policy basis of any such arrangements, and to ensure that the calculation of expected taxation liabilities applied in the Final Decision does not have the effect of defeating the express purpose of such arrangements.[714]

Envestra's submissions included a number of propositions.[715] It argued that the Government intended the benefits of 'accelerated depreciation' to investors, which would be passed through under the Commission's proposed approach.[716] In its late submission, it argued that the Commission's proposed approach:

> unequivocally contravenes the intent of the Fiscal Policy initiative that brought about the implementation of the 20 year effective life caps.[717]

and later that:

> [i]t is very clear from the Minister's press release that the positive taxation and cash flow implications were intended to flow through to the owners of these assets to provide the incentive to invest.[718]

---

714 Multinet, Response to the Draft Decision, pp.88-89.

715 The Commission notes that Envestra quoted out of context a statement from its May 2000 Draft Decision (at p.181) on the price controls for the electricity distributors that has materially altered the meaning of the statement quoted (Envestra, Summary Submission, 12 September 2002, p.12). The passage quoted by Envestra commenced with 'it is more of a theoretical issue as to whether or not regulators should pass on the benefits of accelerated depreciation to customers'. However, the full passage was 'given the recent changes to the company taxation regime in Australia**,** it is more of a theoretical issue as to whether regulators should pass on the benefits of accelerated depreciation to customers'. Given the recent application of effective life caps for gas infrastructure, and Envestra's statements that this amounts to accelerated depreciation, clearly the Commission would no longer consider the issue to be 'theoretical'.

716 Envestra, Response to the Draft Decision, p.55.

717 Envestra, Summary Submission, 12 September 2002, p.12.

718 Ibid, p.13.

Envestra also commented that the reference to competition in the Gas Code has been interpreted to imply the outcome of 'workable competition', not perfect competition, which may include a degree of tolerance of market power.[719] It also argued that the Commission should have regard to the 'broader aspects of political intent and public interest, beyond the promotion of a competitive market',[720] and to 'take into account the policy intent of the 20 year effective life caps and social considerations (ie. non-financial benefits from access to natural gas), not just economic theory'.[721]

Regarding the Commission's interpretation of the tax law, each of the distributors questioned the depreciation rates adopted by the Commission in its Draft Decision. In particular, the distributors have argued that the depreciation rate adopted by the Commission for mains and services acquired prior to September 1999 (Group 1 Assets) of 10.5 per cent is inappropriate, as the ATO Tax Ruling IT 2685 specifies that the permissible rate for these pipelines is 20 per cent.

Envestra and TXU disagreed with the depreciation rate adopted by the Commission for meters installed after September 1999 (post business tax reform). In its Draft Decision, the Commission assumed the distributors would utilise the low value pool for these assets and therefore adopted a depreciation rate of 37.5 per cent declining balance. Envestra and TXU have argued that the use of the low value pool is optional and it should not be assumed that the distributors' would utilise it.

Further analysis

APPROACH TO THE TAXATION ALLOWANCE

The first issue to consider is the approach to be pursued when deriving a benchmark taxation allowance – that is, whether the preliminary view expressed in the Draft Decision that this should reflect an unbiased estimate of taxation liability of an efficient gas distributor should remain. Envestra and Multinet's concerns centre around whether the allowance should be unbiased (to the extent practicable). Their proposal is, in effect, that the Commission should permit reference tariffs to include an allowance for taxation that reflects fewer deductions than permitted by the tax law – which would imply an upward biased allowance for taxation. The specific proposal is that tax depreciation should be able to reflect the 'effective life' of the assets rather than the life permitted by the tax law.

[719] ibid.
[720] ibid.
[721] ibid.

There is no explicit guidance in the Gas Code with respect to the derivation of an allowance for taxation. The Commission has noted previously that the Gas Code provides that returns expected under the reference tariffs should reflect ‘a return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the reference service’,[722] and that such returns are normally estimated in after tax terms. Accordingly, for the return expressed in pre-tax terms to meet this requirement, the allowance for taxation should reflect an unbiased estimate of the cost of tax arrived at on a reasonable basis.[723] This treatment of taxation as part of the ‘return’ on investment is consistent with the treatment of taxation in some of the Australian corporate finance literature,[724] particularly given the common assumption that dividend imputation should be interpreted as reducing the effective rate of company taxation.

The Commission considers that the process of deriving an allowance for the cost of tax is not a matter of discretion, but rather that the Gas Code requires the Commission to establish the best estimate of that cost, arrived at on a reasonable basis in accordance with section 8.2(e). It is self evident that, to derive such an estimate, account must be taken of the implications of the tax law for the distributors’ tax depreciation allowances. Accordingly, Envestra and Multinet’s submissions about the other provisions of the Gas Code for the theoretical issue of whether or not the allowance for taxation should reflect the provisions of the tax law – or be designed to achieve some other purpose – are not directly relevant to the assessment of the distributors’ reference tariffs. That said, the Commission has addressed the merits of Envestra and Multinet’s arguments about the implications of the other provisions of the Gas Code for this theoretical issue, which is set out below.

In the Draft Decision, the Commission referenced a previous statement it had made that ‘[i]n a perfectly competitive market, all of all of the benefit from such a tax allowance would be passed on to users’.[725] In its response to the Draft Decision, Envestra noted that the court in the recent Epic case had decided the reference to a competitive market in section 8.1(b) of the Gas Code is a reference to ‘workable competition’, rather than perfect competition.

Regarding the implications of section 8.1(b), the Commission does not consider that the outcomes of a market that is characterised by ‘workable competition’ are straightforward and that, as a result, the objective does not provide unambiguous guidance on this matter. Envestra’s reference to this objective appears to be that excess returns may be tolerated for some time in a market characterised by workable competition, and so (presumably) the excess returns implied by its use of ‘effective life’ depreciation should be tolerated. However, the Commission notes that markets characterised by workable competition may also deliver inadequate returns for periods of time, but tend towards delivering normal returns over the longer term.

722 Gas Code, section 8.30.

723 Draft Decision, p.251.

724 For example, in categorising the separate recipients of a project’s operating income (return), Professor Officer distinguishes to the share to the equity providers, the share to the debt providers, and the share to the Government (in the form of company taxation): Officer, R., ‘The Cost of Capital under an Imputation Tax System’, *Accounting and Finance*, vol. 34, 1994, pp.1-17.

725 Draft Decision, p.255. The original reference was: Office of the Regulator-General, 2001 Electricity Distribution Price Review: Draft Decision, p.181. Note the concerns expressed about Envestra’s reference to the original statement in footnote 715.

The Commission notes that neither Envestra nor the other distributors discussed the implications of the other objectives in section 8.1. The Commission's views on the guidance provided by the relevant of these objectives are as follows.

- Section 8.1(a) – the use of the tax depreciation rates permitted by the tax law (rather than an assumed allowance) would align revenues expected from services closer to the efficient cost of providing these services, and so be consistent with this objective.
- Section 8.1(d) – the use of tax depreciation rates permitted by the tax law (rather than an assumed allowance) would not be expected to distort investment in pipeline systems because reference tariffs would provide a return equal to (or greater than) the cost of capital in after tax terms. The use of tax depreciation rates permitted by the tax law (rather than an assumed allowance) would be expected to reduce distortions in upstream and downstream industries through the closer alignment of revenue and cost.[726]
- Section 8.1(e) – the use of tax depreciation rates permitted by the tax law (rather than an assumed allowance) would be expected to result in a more efficient level of reference tariffs through the closer alignment of revenue and cost.
- Section 8.1(f) – the use of tax depreciation rates permitted by the tax law (rather than an assumed allowance) would not be expected to impact on the 'efficient growth in the market for services' because reference tariffs would provide a return equal to (or greater than) the cost of capital in after tax terms.

As noted above, regard to the factors in section 2.24 is required to resolve inconsistency between, and assign weight to, these objectives. As also noted above, it is not clear that there is inconsistency between the objectives in section 8.1, although it is noted that the implications of section 8.1(b) are not unambiguous.

The matters relevant to the 'public interest' that Envestra appeared to refer to included:

- the intention of the Government in introducing the 20 year effective life caps; and
- the non-financial benefits from access to natural gas.

Regarding the first of these matters, the Commission is not convinced that its proposal to take account of permitted tax depreciation rates (rather than notional 'effective life' rates) when deriving its benchmark taxation liability would unequivocally contravene the intent behind the introduction of the 20 year effective life caps in the taxation regime.

726 As noted below, the Commission foreshadowed its proposed treatment of taxation – including its views about the treatment of accelerated depreciation – in the 1998 decision. This is relevant to the consideration of whether its proposals in the Draft Decision could be seen to distort investment.

The Commission notes that taxation initiatives, like accelerated depreciation or investment allowances, normally have a public policy objective of the encouraging capital formation in the relevant industries. The Commission does not consider its proposal to take account of the permitted tax depreciation allowances to be inconsistent with this objective. Envestra has also referred to the statement by the Commonwealth Minister responsible for the taxation initiatives that he expected the infrastructure providers to retain the cash flow benefits that would flow from the 20 year effective life caps. The Commission also does not consider that its proposal to take account of the permitted tax depreciation allowances is inconsistent with this outcome.

However, the Commission notes that care must be taken when the implications of measures like accelerated depreciation in a situation where regulated charges are set based upon full recovery of cost are compared with the outworking of such measures in unregulated markets, otherwise a misinterpretation may result. The following simple example demonstrates this point.

- In an *unregulated industry*, participants make an assumption about the price that would have to be offered to customers to compete, and then forecast costs (including taxation) and proceed with a project if it would generate the required return. Where a project was not economic, but the taxation payable in respect of the project were then reduced, there would be 'positive cash flow consequences' from that tax-initiative and, if sufficiently favourable, an uneconomic project may become economic, and investment proceed.
- In a *regulated industry*, tariffs are calculated such that they would provide the required return in addition to a recovery of other costs. If the regulated price were higher than the price required to compete with alternatives, then the project would be uneconomic, and it would not proceed. If the Government then reduced the tax payable in respect of the project, the project would remain uneconomic if the price offered to customers remained unchanged. The only means through which the project may become economic is for the price offered to customers to fall to below the level required to compete with alternatives. Again, if the tax initiative were sufficiently favourable, the reduction in taxation may permit the price that would generate the required return to be lowered sufficiently for the project to be made economic and thus proceed.

Importantly, for a project that was previously uneconomic, but which became just economic after the tax initiative, the price that is charged to customers, cash flows, and returns in the situation of the unregulated market and the regulated markets would be identical. If the regulated project had assessed its cash flows on the assumption that it offered customers the price required to compete (as proponents would in an unregulated market), then the taxation initiative would be interpreted as having favourable cash flow consequences. Accordingly, the Commission considers that its proposal to take account of the permitted tax depreciation allowances is consistent with the objective of promoting capital formation, and consistent with the distributors receiving the cash flow benefits associated with the measure, if interpreted correctly.

Regarding the ‘non financial benefits of natural gas’, the Commission notes that the above discussion implies that its proposed response to 20 year effective life caps is consistent with the achievement of extensions of natural gas in Victoria. However, the Commission also notes that the vast majority of Envestra’s system is established and in urban rather than regional areas.

The Commission considers that there are also a number of other matters that are relevant to its assessment of the arguments presented by Envestra. Envestra has asserted that the 20 year effective life caps represent ‘accelerated depreciation’. The implication of Envestra’s arguments is that the Commission should calculate reference tariffs based upon the assumption that tax depreciation reflects the rate of economic depreciation. However, as the Commission remarked in the Draft Decision, the rate of economic depreciation is not known, can only be estimated, and is highly sensitive to a number of assumptions. Envestra has not presented any analysis to demonstrate that the use of ‘effective life’ depreciation would be a reasonable proxy for economic depreciation.

Indeed, when advocating for the 20 year effective life caps, the gas industry argued that tax lives that were shorter than their effective lives would be required to reflect the rate of economic depreciation. For example, the Australian Gas Association commented as follows.

> The AGA continues to make representations to ATO/Treasury and other policy players regarding the revision of the effective life schedules for plant and equipment for depreciation purposes. The AGA, the Australian Pipeline Industry Association and the Australian Council of Infrastructure Development have also completed a major study to assist in the definition of 'effective life' for long lived assets.
>
> The study was commissioned to assist in industry's representations to the Capital Allowances Focus Group convened by Treasury and the ATO. The study also serves as a response to the ATO in the context of its review of 'effective life' as specified in IT Ruling 2685. This was a matter identified in the Review of Business Tax for the Tax Commissioner to review so as to ensure the schedule is as representative and comprehensive as possible.
>
> The report illustrates that economic factors such as inflation, technological and economic obsolescence and/or changes in supply and demand conditions will result, in practice, in the economic life of long lived assets being considerably less than their physical life. The AGA, APIA, and AusCID argue that failure to recognise these factors will result in a taxation system that actively discriminates against long-lived assets. The three organisations will continue to lobby Government on the issue and are scheduled to hold a high level briefing in Canberra for officials on Friday 26 May. [727]

Similarly, the Executive Director of the Australian Pipeline Association commented as follows:

> Before being accused of “special pleading”, let me set the situation out by reference to the legitimate concerns this industry has about physical life as a basis for effective life.

[727] Australian Gas Association, Newsletter, May 2000.

> It is true that the physical life of a transmission pipeline can be very long.
>
> However, this can be related back to the circumstances relating to pipeline licences which require a prudent pipeline owner to provide adequate asset protection through appropriate design and construction (eg AS 2885), appropriate physical protection of the buried asset (cathodic protection, protection against third party damage) and appropriate inspection of the asset (eg pipeline inspection devices).
>
> Pipelines have an excellent safety record. Such incidents fall in the "low probability/high potential consequence" category and hence the pipeline industry views pipeline integrity and monitoring as a critical issue.
>
> Under such circumstances the physical life could be very long provided gas reserves and markets remain available. However, for investment planning purposes the "economic" life will be the determining factor – invariably this will be much shorter than the physical life and should be the key criteria in determining "effective life". [728]

Accordingly, even if the Commission were to accept that economic rather than tax depreciation should be used to calculate the benchmark taxation liabilities, the arguments presented elsewhere by the gas industry would suggest that the 20 year life would be a closer approximation than the use of a physical life.

The Commission also notes that, in its representations to Commonwealth Ministers, the pipeline industry has argued that the longer depreciable lives expected after the Ralph review may lead to higher prices to customers. For example, the Australian Pipeline Industry Association (APIA) has stated that:

> Based on modeling provided by APIA to the Government, ATO's 50 year proposal would translate to a 20 percent increase in pipeline haulage tariffs (relative to the arrangements that applied before September 1999, when the Ralph Initiatives were announced). This would discriminate against new pipeline development and customers (who would bear the extra costs) in emerging markets, particularly in developing states like WA, NT, Queensland, South Australia and Tasmania. [729]

It is noted that slower rates of tax depreciation would only result in higher prices as cautioned by APIA if it was expected that regulators would adopt the slower tax rates when setting regulated charges. Conversely, the 20 year cap on effective life could only avoid the higher prices if regulators adopted the faster rate of depreciation (ie that applicable under the 20 year cap) when setting regulated charges that the Government has just announced.

---

[728] Beasley, A., 'Business Tax Reform and Effective Life', Presentation to AGA Gas Industry Forum, 28 June 2000, Melbourne.

[729] APIA Submission to the Senate Economics Committee, Tax Effective Life, 21 June 2002.

Lastly, the Commission considers that its position in the Draft Decision that the allowance for taxation in reference tariffs should reflect the tax depreciation allowances permitted by the tax law, rather than another notional rate was clear at the time of its 1998 review. In that review, the applicant proposed the use of a long term effective tax rate. The Commission adopted that framework in the Draft Decision, but used its own estimate of the long term effective tax rate in the 1998 Draft Decision. The issue of contention subsequent to the 1998 Draft Decision was whether it was possible to estimate the long term effective tax rate with any precision, given its sensitivity to economic and business variables that need to be forecast over long periods. In its 1998 Final Decision, the Commission conceded the difficulties with estimating a long term effective tax rate, and adopted the statutory tax rate as a proxy, stating:

> However, given the practical difficulties in establishing any reasonable estimate of the long-term effective tax rate for the purposes of this Final Decision, the Office has accepted the view that the 36 per cent statutory tax rate provides an estimate of the effective tax rate that is no less appropriate than any other.[730]

When the 1998 Decision was made, the tax depreciation rates for many of the distributors' assets were more favourable than at present, including for the assets that are subject to the 20 year effective life cap. As noted above, the Commission foreshadowed a review of the treatment of taxation in the 1998 Decision, and discussed a number of options for improving the accuracy of the allowance for taxation. One of these options was to forecast taxation liabilities over the next five year access arrangement period only rather than the long term. This is the approach the Commission adopted in the 2002 Draft Decision. As was noted at the time of the 1998 Decision:

> Deriving a soundly-based estimate of the long-term effective tax rate appears unachievable because of the need to resort to estimates of economic and business variables over periods so long that the original objectives of the exercise become seriously compromised.
>
> It is also inevitable that the rates and even the method of taxation will change over the economic life of the assets. Using a long-term average tax rate assumption (which assumes a degree of pre-payment of tax in respect of expected future tax liabilities) makes it complex to respond to changes to the tax law without delivering windfall gains or losses, either to the businesses or their customers.
>
> Nevertheless, the consequence of misjudging the effective rate of tax is that investors will be over or under-rewarded for the risks they bear. The Office's own modeling work suggests that, once fixed payments to debt holders have been taken into account, significant errors in the allowance for tax have a disproportionate impact on after-tax returns to equity. These errors are compounded when the time profile of tax payments is not smooth.[731]

Statements such as these, made by the Commission made in its 1998 Review, are also relevant to the consideration of the public interest.

---

730 1998 Decision, p.76.

731 1998 Decision, p.226.

Regarding the most appropriate means of deriving such a benchmark tax allowance, in the absence of further submissions from the distributors not addressed above, the Commission confirms the view it expressed in the Draft Decision, that the most appropriate approach is to make an explicit calculation of the company tax liability expected over the next access arrangement period on the basis of a set of tax-related assumptions. The Commission also remains of the view that it is appropriate to use industry-wide benchmark assumptions where the distributors would otherwise have discretion under the tax law, based upon the decisions expected from a reasonably prudent business operating in line with standard industry practice. The Commission's further analysis of such assumptions is set out below.

TAX RELATED ASSUMPTIONS

Regarding the tax related assumptions adopted, those related to the non-depreciation elements of the benchmark tax calculation were as follows:

- Assessable revenue – assumed to be the revenue benchmark, including customer contributions;
- Operating expenditure – assumed to be the operating expenditure benchmark;
- Capital expenditure – taken as historical and forecast capital expenditure (noting that a portion of capital expenditure will be immediately deductible); and
- Interest deduction – taken as the nominal interest payments implied by the benchmark financing arrangements.

For the purpose of deriving a benchmark tax depreciation allowance, the Commission derived its own assumptions regarding the assets that are relevant for taxation purposes, and the rates of depreciation that are applicable to each class. The Commission split the asset classes into three distinct groups to separate assets according to the prevailing depreciation allowances:

- Group 1 – opening asset value for tax purposes as at 1 July 1996 plus additions to the tax asset base up until 20 September 1999 (pre business tax reform);
- Group 2 – additions to the tax asset base from 21 September 1999 (post business tax reform) to 30 June 2002; and
- Group 3 – additions to the tax asset base from 1 July 2002.

In its Draft Decision, the Commission adopted the following classes of assets and applicable depreciation rates:

TABLE C.13

DRAFT DECISION – BENCHMARK ASSET CLASSES AND RATES

	Group 1	Group 2	Group 3	Method
Mains and services	10.5%	3.0%	7.5%	Declining balance
Meters	20%	37.5%	37.5%	Declining balance
Land and buildings	2.5%	2.5%	2.5%	Straight line
Other assets	15%	15%	15%	Declining balance

After the release of the Draft Decision, the Commission received responses from each of the distributors in relation to the assumption adopted in estimating the benchmark cost of tax. The specific issues raised by the distributors will be addressed separately in the following section.

Each of the distributors argued that the depreciation rates adopted in the Draft Decision for Group 1 assets were incorrect. However, these rates depend on the Tax Commissioner's scheduled expected useful lives, which adopts a broad-banding approach for these assets (see table C.14 below).[732]

TABLE C.14

DEPRECIATION RATES

Effective Life (Years)		Depreciation Rate	
Greater than	**Less than**	**Prime cost**	**Diminishing value**
0	3	100%	100%
3	5	40%	60%
5	$6^{2/3}$	27%	40%
$6^{2/3}$	10	20%	30%
10	13	17%	25%
13	30	13%	20%
30		7%	10%

In its Draft Decision, the Commission adopted a depreciation rate of 10.5 per cent[733] for mains and services assets, based on an effective life of greater than 30 years. Each of the distributors have argued that Income Tax Ruling 2685 permits a distributor to adopt a depreciation rate of 20 per cent diminishing value for mains and services pipes. The Commission accepts that IT Ruling 2685 allows for a depreciation rate of 20 per cent for these assets and has made the appropriate adjustment to the depreciation allowance for each of the distributors.

732 Envestra, Response to Draft Decision, p.56.

733 This rate was erroneously based on the effective life of greater than 30 years, the correct rate should have been 10 per cent diminishing value.

Envestra and TXU have also argued that the Commission's Draft Decision incorrectly applied a depreciation rate of 20 per cent diminishing value for Group 1 meters. Both have noted that because the capital cost of the majority of these assets is lower than $300, an immediate deduction is allowable. The Commission acknowledges that table C.17 of the Draft Decision showed that it had used a rate of 20 per cent diminishing value, which was erroneous. The Commission adopted a rate of 100 per cent for its price control model, consistent with the assumptions noted by Envestra and TXU regarding the capital costs of these assets.

Envestra and TXU have also argued that the Commission's adoption of the low value pool for Group 2 and 3 meters is incorrect. In its Draft Decision, the Commission formed the view that as the majority of these meters are valued at less than $1 000, the distributors would elect to depreciate them via the low value pool – and therefore adopt an effective life of 4 years, as permitted by taxation law. Moreover, the Commission applied this methodology to all meters purchased after September 1999 (Group 2), despite the fact that low value pooling did not apply until 1 July 2001.

In response, Envestra and TXU have argued that the adoption of the low value pool is at the discretion of the distributor. TXU noted that its practice is not to adopt the low value pool[734], whilst Envestra argued that it is not appropriate to assume that a distributor would adopt the low value pool[735]. Envestra proposed that the Commission assume an effective life of 25 years with a depreciation rate of 6 per cent diminishing value.

As noted above, the Commission's approach in respect of the appropriate allowance for taxation is one that would reflect an unbiased estimate of the taxation liabilities for an efficient company. It is the Commission's view that an efficient company would seek to minimise its taxation liabilities, and if this could be achieved by adopting a method for depreciation that would yield the greatest tax deduction, the distributor would do so.

In a further response to the Draft Decision, TXU appeared to agree with the Commission's position on this matter by stating:

> For the purposes of deriving an unbiased estimate of the cost of tax it should be assumed that *prima facie*, TXU Networks would seek to minimise its tax liabilities in a *competitive market* (consistent with the requirements of section 8.1 of the Gas Code).
>
> TXU Networks would therefore adopt the most favourable depreciation rates available at any given point in time to ensure that its taxation liabilities are minimised.[736]

As a result, the Commission believes that adopting an approach whereby the distributor would utilise the low value pool in order to minimise its taxation liabilities is appropriate.

---

734 TXU, Response to Draft Decision, Attachment F, Submission on Cost of Tax, 7 August 2002, p.2.

735 Envestra, Draft Decision Submission, August 2002, p.58.

736 TXU, Cost of Tax – Tax Depreciation, 12 September 2002, p.1.

In its response to the Draft Decision, TXU noted that the Commission had incorrectly applied depreciation to the asset class 'land and buildings'. TXU argued that land is not depreciated for taxation purposes and that the amount of $5.147million should be deducted from its 1 July 1996 tax asset base. The Commission acknowledges that land is not depreciated for taxation purposes and therefore has deducted the amount reported by TXU. The Commission also confirmed that neither Envestra nor Multinet included an amount for land in their taxation-related information.

TXU also argued that the Commission should adjust tax losses going forward to reflect the fact that the value of these losses diminishes over time as they can only be offset against future tax profits.[737] The Commission agrees with TXU's contention, and it has already implicitly allowed for this in its financial model by calculating tax losses in historical terms.

Envestra has argued that the depreciation rate of 15 per cent diminishing value adopted by the Commission in its Draft Decision with respect to Group 1 - other assets is not an allowable rate under the broad band accelerated depreciation rates.[738] Envestra has noted that the typical depreciation rates permissible under IT Ruling 2685 for these other assets results in an average rate of 30 per cent diminishing value.

The Commission acknowledges that the depreciation rate adopted in its Draft Decision is not an allowable rate. The Commission agrees with the proposal by Envestra to adopt a rate of 30 per cent diminishing value, and believes that this rate reflects an appropriate view on the average effective lives of these types of assets. As a result, the Commission will adjust the depreciation rate for each of the distributors for Group 1 – other assets to 30 per cent diminishing value.

Envestra and Multinet argued that the Commission's decision to adopt a 20-year effective life cap on its mains and services assets for the period from 1 July 2002 is inappropriate, and that the Commission should adopt a rate that instead reflects an effective life of 50 years. In its Draft Decision, the Commission adopted a tax depreciation cap of 20 years for distribution infrastructure assets from 1 July 2002, consistent with amendments to taxation law announced by the Treasure in the Federal Budget Speech.

Envestra and Multinet both contend that the proposal by the Treasurer is not law yet and therefore should not be relied upon when adopting an appropriate depreciation rate for these assets. However, the Commission has received advice that the proposed legislation has been passed by Parliament and that it received Royal Assent on 29 June 2002.

---

737 TXU, Attachment F to TXU Networks Response to the Draft Decision on the Review of Gas Access Arrangements, Submission on Cost of Tax, 7 August 2002, p 2.

738 Envestra, Response to Draft Decision, p.57.

Envestra and Multinet have also argued that the cap on these assets is not compulsory and that its adoption is at the taxpayer's discretion.[739] As stated above, it is the Commission's view that an efficient company would seek to minimise its taxation liabilities, and if this could be achieved by adopting a method for depreciation that would yield the greatest tax deduction, the distributor would do so. Therefore the Commission does not accept the proposal by Envestra and Multinet to adopt a rate reflecting a 50-year effective life.

In its summary submission, Envestra argued that a mains replacement would be a repair, and therefore fully deductible, unless it enhanced the capacity of the system, in which it would be depreciable.[740] Envestra also noted that it would not be practical or reasonable to forecast which replacements enhanced capacity. Envestra proposed not to forecast any mains replacements as repairs for the next access arrangement period.

The Commission expressed the view in its Draft Decision that the replacement of a distribution pipe constitutes a repair to that 'unit of property' unless the replacement provides additional capacity or a low-pressure pipe is replaced with a high-pressure pipe. The Commission does not accept Envestra's argument that it is unreasonable to forecast replacements that enhance capacity of the network and therefore believes that Envestra's original forecast should remain as the most appropriate.

Table C.15 below summarises the tax depreciation rates adopted by the Commission for this Final Decision.

TABLE C.15
FINAL DECISION – BENCHMARK ASSET CLASSES AND RATES

	Group 1	Group 2	Group 3	Method
Mains and services	20%	3.0%	7.5%	Declining balance
Meters	100%	37.5%	37.5%	Declining balance
Buildings	2.5%	2.5%	2.5%	Straight line
Other assets	30%	15%	15%	Declining balance

C.8.2 Franking credits

Background and distributors' proposals

In its consultation papers prior to the Draft Decision, the Commission noted that, amongst other things, the assumption about the value of franking credits should be consistent with the assumptions adopted elsewhere in the assessment of the distributors' price controls, and otherwise reflect the latest empirical evidence on the value of franking credits.

[739] Envestra, Response to Draft Decision, 9 August 2002, p.58; Multinet, Response to the Draft Decision, 7 August 2002, p.88.

[740] Envestra, Summary Submission, 12 September 2002, p.14.

In previous decisions – including in the 1998 gas decision – one issues has been the appropriate assumption about the national identity of the equity participants in the industry. In the 1998 decision, the Commission expressed the view that it is appropriate to assume that the only practicable benchmark assumption about national identity is that of the average Australian investor, and that foreign investors should not be disadvantaged if this assumption is applied consistently across all benchmark assumptions.[741] The value of franking credits assumed (0.5) reflected the Commission's best estimate of the market value of franking credits in Australia at the time.[742]

In its consultation papers prior to this review, the Commission also referred to comments received during a previous review that the adoption of an assumption that franking credits (once distributed) are not fully valued is inconsistent with the form of the CAPM that Commission has employed.[743] In particular, it was noted that the form of CAPM the Commission has used assumes that capital markets are completely segregated – and consistency would require the assumption that virtually all of the franking credits created may be utilised once distributed (and hence a higher gamma).

The alternative approach would be to assume that asset prices are determined with reference to an internationally diversified portfolio of stocks, which would justify an assumption of zero for 'gamma', but also require a different assumption about the equity premium and the proxy beta. While the question of which model should be preferred is an empirical matter, the Commission produced estimates during its review of the price controls for the electricity distributors that suggested a pure application of either model may deliver a lower estimate of the cost of capital than that implied by the Commission's approach (that is, where the impact of foreigners on the value of imputation credits is taken into account, but not elsewhere).

In their submissions accompanying their Access Arrangement Revisions, all of the gas distributors adopted an assumption that franking credits should not be ascribed any value.

Envestra's principal argument was that the value of franking credits should reflect the value placed upon them by the marginal investor, and that marginal investors are either foreign investors or domestic institutional investors (such as superannuation funds) who have not benefited from the introduction of dividend imputation. It also argued that the introduction of capital gains tax would have offset the impact dividend imputation on investor returns. Envestra referred an article by Lonegran to support its propositions.[744]

---

741 1998 Decision, pp.205-207.

742 More precisely, this was assumed as the value of a franking credit (as a proportion of its face value) at the time of creation. The 'gamma' parameter the Commission has used assumes that a proportion of franking credits created are not distributed, or are distributed with a delay (and thus suffer a decline in value because of the time value of money).

743 Consultation Paper No. 1, p.67. The comments were included in: Lally, M., Response to 2001 Electricity Distribution Price Review Draft Decision. The comments made by Dr. Lally in that submission are set out in more detail in Lally, M., 2000, *The Cost of Equity Capital and its Estimation*, McGraw Hill Series in Advanced Finance, Vol. 3, (McGraw Hill, Sydney).

744 Lonegran, W., 'The Disappearing Returns', *JASSA*, Autumn 2001.

TXU and Multinet referred to the paper by Professor Gray the distributors had commissioned in response to the Commission's Position Paper, as well as an independent empirical study on the value on franking credits that was co-authored by Gray.[745] With respect to the latter, TXU and Multinet argued that the findings in that empirical study provide a sound basis for estimating the value of franking credits, which it found to be approximately zero. TXU and Multinet responded to a number of technical comments that the Queensland Competition Authority had made on that empirical study.

TXU and Multinet also commented on the distinction that the Commission (on the advice of Dr Lally) had made between the domestic and international CAPM, and argued that it was impossible to estimate segregated cost of capital parameters because the Australian data already reflects the presence of foreign investors.

Professor Gray's submission in response to the Position Paper covered two issues. First, Gray discussed a number of the existing empirical studies on the value of franking credits, and drew attention to a number of weaknesses in the use of those studies that rely upon the size of 'dividend drop-offs' or traded prices of new rights issues to estimate the value of franking credits. He emphasised that the study he co-authored had a number of desirable features, including greater precision in the estimates of the value of franking credits.

The second set of comments of Professor Gray related to the differences between the use of a domestic CAPM and international CAPM, and so implicitly on the views that Dr Lally provided to the Commission during its review of the price controls for the electricity distributors in 2000, and on the Commission's analysis in the reasons for its electricity determination, as summarised above. Gray's analysis suggested that, in contrast to the views presented by the Commission in 2000, the world equity premium is likely to be higher than the Australian domestic equity premium, and that the betas for gas Australian gas distribution businesses are likely to be higher when measured against the world market than against the Australian market.

Professor Gray also emphasised the imperfections associated with the various forms of the international-CAPM, and the complexity associated with trying to identify – and implement – the best model. Lastly, Gray drew attention to a recent study that demonstrated how any bias associated with using a domestic CAPM if assets really are priced according to an international CAPM, and concluded that the use of a domestic CAPM was a reasonable approximation to the more theoretically correct international CAPM.

Draft Decision

In the Draft Decision, the Commission expressed the preliminary view that it is appropriate and consistent with objective market evidence to assume that imputation credits *created* are valued at 50 per cent of their face value. This is the same assumption that the Commission adopted in the 1998 Decision.

---

[745] Cannavan, D., F. Finn, and S. Gray, The Value of Dividend Imputation Credits, Working Paper, University of Queensland and Duke University, 2002.

The Commission noted that one of the implications of this treatment of franking credits is that it implies that the *cash* level of return that investors require on equities would have fallen with the introduction of dividend imputation by an amount that reflects the value of the franking credits. As has been noted previously, this can be interpreted as investors requiring the same return – but with the return being received in a different form (ie as a franking credit rather than as a cash dividend).[746] If ? reflects the value of a franking credit (as a proportion of its face value) once distributed to shareholders, F the average franking ratio of dividends, D dividend yield and T the prevailing company tax rate, then the portion of the return on the market portfolio that investors would be receiving through franking credits can be calculated as:

$$\text{Franking Return (\%)} = q.D.F.\left(\frac{T}{1-T}\right)$$

If ? is assumed to be 0.60 and F is 83 per cent, and current market data for D and T are used (3.2 per cent and 30 per cent, respectively), then the estimate of the franking return was noted to be approximately 0.7 per cent.[747]

It was noted that the value of franking credits at the time of creation is dependent upon two assumptions, which are:

- the value of franking credits (as a proportion of their face value) once they are distributed to shareholders; and
- the proportion of franking credits distributed.[748]

The Commission's assumption of 0.5 for 'gamma' reflected an assumption that franking credits distributed are valued 60 per cent of their face value, and that 82 per cent are distributed. The assumption about the proportion of franking credits distributed was based upon the finding of Professors' Officer and Hathaway.[749]

Regarding the value of franking credits once distributed, available empirical estimates of the value of franking credits were presented. It was noted that, to date, five different methodologies have been employed, and the estimates for the value of franking credits range from virtually worthless to almost fully valued. In discussing these results, the Commission addressed the concerns raised in the submission by Professor Gray about the reliability of the results produced by the different estimation methods. One of the specific concerns addressed was whether it was appropriate for the value of franking credits to reflect a market wide average, or the specific composition of an entity's shareholder base. The Commission concluded that a market-wide estimate is the more appropriate benchmark.

---

746 Office of the Regulator-General, Weighted Average Cost of Capital for Revenue Determination – Gas Distribution Staff Paper No. 1, May 1998, p.25

747 If follows that if the *cash* equity premium could be observed at the present time, it would be necessary to add on 0.7 percentage points to make it consistent with an *imputation-inclusive* equity premium. The estimate of the franking ratio is taken from Hathaway, N., R. Officer, The Value of Imputation Tax Credits, working paper, Melbourne Business School, 1996, p.12.

748 The proportion distributed is also a proxy for the time value loss associated with a delay in distribution.

749 Hathaway, N., R. Officer, The Value of Imputation Tax Credits, working paper, Melbourne Business School, 1996, p.13. More precisely, Hathaway and Officer found that the value of franking credits distributed in each year averaged 82 per cent of the value of credits created, which Hathaway and Officer used as a proxy for the proportion of credits created in a year that are distributed.

The Commission noted that it was not convinced that it is appropriate to place sole weight on the recent working paper by Cannavan, Finn and Gray, as the distributors had proposed, but rather that it is appropriate to place weight on all of the studies. It further noted that there is no single accepted methodology for estimating the value of franking credits, and that all of the studies have advantages and disadvantages. Having regard to the results of the empirical studies, and the comments about the relative merits of the different studies, the Commission concluded that 0.60 provides a reasonable estimate of the market value of franking credits once distributed.

Regarding Professor Gray's comments about the size of the equity beta, the Commission rejected the conclusion that the equity beta of an Australian gas distributor would be higher when measured against the world market than when measured against the Australian market. It was noted that the empirical method employed by Gray was conceptually flawed, and that the available empirical research suggested that the equity betas of Australian firms would be substantially lower when measured against the world portfolio of assets than against the Australian portfolio. The suggestion that the equity premium in an integrated world market would be higher than the premium in a segregated Australian market was also rejected. The Commission referred to research that suggested the estimation method employed by Gray to derive a world equity premium was invalid. The research referred to by the Commission suggested that the additional opportunities for diversification should imply a reduction in the equity premium for all countries.[750]

The Commission also addressed the comments from the distributors about whether the assumptions employed in its estimate of the cost of capital actually reflect segregated capital markets. The Commission noted that the available evidence did not suggest that interest rates had been affected by internationalisation. It noted that the real risk free rate employed in the Draft Decision was 3.5 per cent, whereas the average real risk free rate over the period since 1882 (and which has been reflected in the equity premium) was 2 per cent. It also noted that it had measured equity betas and derived its benchmark gearing assumption with reference to Australian firms.

The Commission addressed the comment from Professor Gray and Envestra, who had argued that the assumption that franking credits have value in the presence of foreigners is 'inconsistent with the basic notion of equilibrium'.[751] The Commission disagreed with this view, noting that even if the price of Australian assets reflected the full value of franking credits, foreigners would still invest if their advantages over domestic investors (such as being able to achieve a greater degree of diversification) more than offset that tax disadvantage, which the Commission's analysis suggested would likely be the case.

750 Draft Decision, pp.266-268.
751 Draft Decision, pp.269-270.

Lastly, the Commission responded to the views expressed by Lonegran in an article referred to by Envestra, who argued that the price setting investor does not value franking credits. The Commission noted that, while these views were inconsistent with the Commission's view of the empirical evidence discussed above, Lonegran also assumed an equity premium of 5 per cent, which suggested that his assumption about the price setting investor was applied consistently across all of his assumptions. It was noted if all of the assumptions adopted by Lonegran were employed (and not just his assumption about the value of franking credits), the estimate of the cost of capital associated with the distributors' regulated activities would fall.

Responses to Draft Decision

The distributors commissioned Professor Gray to respond to a number of matters related to the value of franking credits, which were adopted in their separate submissions.[752] Accordingly, Gray's comments will be discussed first.

Professor Gray reiterated the view he expressed in his earlier submission that the 'gamma' assumed for a firm should reflect the composition of the shareholders of the particular firms, rather than a market average. He argued that this would imply assuming a significant share of foreign ownership for the Victorian gas distributors and that:[753]

> In particular, a firm that is wholly owned by resident tax-paying investors will have a marginal price-setting investor who fully values franking credits. Conversely, a firm that is wholly owned by non-resident investors will have a marginal investor who does not fully value franking credits. Clearly, the relevant value of franking credits depends on the identity of the marginal investor, which in turn depends on the composition of the shareholder base.

It was also argued that to adopt a market average for this input is 'absolutely inconsistent with the Commission's practice on other inputs to the WACC',[754] such as the use of a beta or gearing assumption that differs from the market average.

The implication was that the Commission should place most weight on the empirical estimates of the value of franking credits that derive estimates specifically for firms with a substantial foreign ownership, rather than on studies that relate to market averages for gamma.

---

752 Gray, S., Response to the Draft Decision, 29 July 2002.
753 ibid., p.5.
754 ibid.

Professor Gray also made a number of comments about the Commission's observations on the application of the segmented-markets versus integrated-markets CAPM. On the application of the segregated-market CAPM, it was noted that, under this model, an estimate of the value of franking credits is not required. It was also questioned whether the benchmark capital structure could be maintained without offshore funds. However, use of a CAPM that assumes the absence of foreigners is inconsistent with the fact that there are foreign investors in Australia, and secondly, that an inconsistency with the identity of the investors is only one of the theoretical inconsistencies with the CAPM applied. He advocated using a model that is consistent with commercial practice, and that:[755]

> It is standard commercial practice to apply domestic CAPM discount rates to multi-period projects and to use a domestic CAPM with an estimate of gamma that allows for the existence of foreign investors.

Lastly, Professor Gray commented on some of the studies summarised by the Commission in the Draft Decision, drawing attention to problems with the precision, empirical techniques or generality of the results.[756]

In their submissions, all three distributors maintained their views that a value of zero for gamma is appropriate, and referred also to Professor Gray's submission.[757] In addition, they each made similar observations about the Commission's comments related to the results from a segmented-markets CAPM. For example, regarding the risk free rate, the distributors argued:

> argued that there was no clear evidence that real interest rates have become lower as a result of internationalisation. This provides an example of the Commission dismissing evidence that is not consistent with its view of what should have happened.[758]

Elsewhere, they commented that the Commission had noted that any country risk premium for Australia would be reflected in the risk free rate. It was also commented that the segmented market equity premium may be higher than that adopted in the Draft Decision.[759] Lastly, the comments of Professor Gray were reiterated that the use of a market-wide value for franking credits rather than a company specific value to generate a cost of tax benchmark is inappropriate.[760]

Envestra also submitted a late submission that included a detailed attachment on the value of franking credits. This submission included material not previously presented that related to the proportion of franking credits that are paid out, and the market value of franking credits once distributed. The Commission's consideration of this submission is set out below.[761]

---

755 Gray, S, Response to the Draft Decision, p.5.

756 ibid., pp.6-9.

757 TXU, Response to the Draft Decision, p.12; Multinet, Response to the Draft Decision, p.70; Envestra, Response to the Draft Decision, p.51.

758 ibid., TXU, Attachment D, p.22; Multinet, Attachment C, p.21; Envestra, p.51.

759 ibid., TXU, Attachment D, p.23; Multinet, Attachment C, pp.21-22; Envestra, p.51.

760 ibid., TXU, Attachment D, pp.23-24; Multinet, Attachment C, p.22; Envestra, pp.51-52.

761 Envestra, Summary Submission, Attachment B, 12 September 2002.

Further analysis

As the Commission has noted in all discussion of the issue, the appropriate treatment of franking credits when valuing assets remains an issue of controversy in Australia. The approach the Commission has taken in previous reviews – which has been adopted by all Australian energy regulators – is to treat franking credits as an offset to the particular entity's company taxation liability.[762] In its 1998 review of the gas access arrangements, the Commission took account of the views of numerous experts on finance theory, as well as a wide range of practitioners, and was convinced that the treatment of franking credits it adopted was both robust, and reflected the dominant (but not universal) approach amongst finance practitioners. No evidence has been presented to the current price review that would contradict this view of current market practice.[763]

The Commission has accepted previously that the value of franking credits *created* (which is relevant when assessing regulated charges) depends upon two assumptions, which are:

- the value of franking credits (as a proportion of their face value) once distributed to shareholders; and
- the proportion of franking credits that are actually distributed (or the loss in value associated with a deferral in distribution).

The product of these two identities is commonly referred to as the gamma (γ). In the Draft Decision, the Commission assumed that regulated businesses distribute the same proportion of franking credits created as the average across all companies – which is 82 per cent.[764] While it would be probable that companies paying the low rates of taxation forecast for the distributors would distribute all of the franking credits created in any year, the assumption that only 82 per cent of franking credits are distributed has been retained for the purposes of this Final Decision.

Regarding the value of franking credits *once in the hands of investors*, the main issues raised in submissions to the Draft Decision were:

- whether the benchmark assumption about the identity of the investors should reflect the average composition of the Australian market, or the specific national identity of the owners of the distributors; and
- the Commission's comments about the implications of applying a segmented-markets CAPM consistently, rather than the version of the CAPM applied by the Commission.

[762] This approach to the treatment of franking credits is derived from Officer, R., 'The Cost of Capital under an Imputation Tax System', *Accounting and Finance*, vol. 34, 1994, pp.1-17.

[763] Professor Gray would appear to support this summary of current market practice: Gray, S., Response to the Draft Decision, p.4-5.

[764] Hathaway, N., R. Officer, The Value of Imputation Tax Credits, working paper, Melbourne Business School, 1996, p.13. More precisely, Hathaway and Officer found that the value of franking credits distributed in each year averaged 82 per cent of the value of credits created, which Hathaway and Officer used as a proxy for the proportion of credits created in a year that are distributed.

BENCHMARK OWNERSHIP ASSUMPTION

Regarding the benchmark assumption employed about the national identity of the shareholders of the distributors, the Commission has addressed this issue in each of the major reviews it has undertaken to date, and in all cases has reached the same conclusion as that in the Draft Decision. The Commission considered a submission from Professor Gray as part of its review of the price controls for the electricity distribution businesses in 2000,[765] and rejected the arguments presented in that submission for the following reasons:

> The [Commission] considers that, to the extent an assumption about the ownership structure of the industry is required, then *benchmark* assumptions rather than the *actual* ownership structures of the relevant distributors, should be employed. The use of a *benchmark* assumption about the identity of the equity participants in the distributors will ensure that the distributors have the incentive to implement efficient financing arrangements and retain the benefits from outperforming financing assumptions, but also protect customers from inefficient financing decisions …
>
> The [Commission] considers that the only practicable benchmark is that of the average Australian investor. Benchmarks where the nationality of equity investors may affect the benchmark WACC and tax wedge – in particular, the real risk free rate, equity premium, company taxation regime and asset beta – reflect an implicit assumption that the investor is Australian. If a lower gamma value were used on the basis that the relevant firm or industry has a higher level of foreign participation than the average Australian firm, then consistency would require the same assumption to be reflected in all other benchmarks. This would not be a practicable exercise.
>
> Moreover, in principle, it is unlikely that the choice of benchmarks as to ownership would result in a material difference to the benchmark revenue requirements for the distributors, provided that the ownership assumption is applied consistently across all benchmarks. If the cost of Australian-sourced equity finance for the distributors was significantly lower than the cost of equity finance from foreign investors (eg. as a result of dividend imputation), then Australian investors would place a greater value upon the cash-flows generated by the entity. This, in turn, would be expected to result in a sale of the relevant interest to Australian investors. Importantly, such a process would be the outcome of market forces, and would be unaffected by any assumptions as to ownership that might be implied by the regulatory regime.
>
> However, the fact that there is a mixture of Australian and foreign-investor equity participation amongst the Victorian electricity distributors suggests that there is no material difference in the cost of Australian-sourced equity finance relative to equity finance from foreign investors. This in turn suggests that any advantages that Australian equity investors receive through dividend imputation are offset by advantages that are enjoyed solely by foreign equity investors.[766]

The point in the third paragraph is worth reiterating. To assume that the cost of capital associated with a firm's activities (and therefore its market value) depends upon the specific characteristics of its shareholders requires the assumption that those shares – or the firm as a whole – cannot be traded, which is not the case for the Victorian gas distributors.

---

765 Gray, S., Response to Consultation Paper No. 4, 4 June 1999.

766 Electricity Distribution Price Review, Draft Decision, May 2000, pp.188-189.

The Commission also does not accept that there is any inconsistency between the use of a market-average value for franking credits and firm specific assumptions about the equity beta, financing arrangements, costs, prices, demand and any other assumption adopted in the assessment of reference tariffs, as argued by the distributors and Professor Gray.

The systematic risk associated with the Victorian gas distributors (under the CAPM) is the same for any person who may own the asset – systematic risk depends upon the relationship between the returns to the businesses and the market as a whole, and is independent of ownership. Similarly, the gearing levels that can be maintained and debt margin charged would depend upon the characteristics of the firm's cash flow, and not the national identity of its owners. Similarly, irrespective of the national identity of the distributors, the same amounts would need to be spent to maintain, renew and extend the gas distribution systems.[767] Thus, trade in the ownership of the assets cannot result in the beta, gearing or expenditure requirements converging to any sort of market average.

Accordingly, for the purposes of the Final Decision, the Commission confirms its view in the Draft Decision that any benchmark about the national identity of equity investors should reflect that of the average investor in the Australian market.

In the Draft Decision, the Commission noted that around five different methods have been used to estimate the market value of franking credits, which are:

- Aggregate taxation statistics – the average utilisation of franking credits is assumed to provide a proxy for their market value. The average utilisation, in turn, is taken as the proportion of credits distributed in any year that find their way into the hands of taxable investors.
- Dividend drop-off studies – the extent to which share prices drop at the time a dividend is paid are observed,[768] and the implied value of franking credits estimated from the size of the reduction. Investors are assumed to be indifferent between buying a share immediately before the dividend is paid, and immediately afterwards. The investor who buys immediately before dividends are paid receives the dividend and attached franking credits, but – as a greater portion of the economic income is received as dividends – foregoes any tax benefit associated with capital gains.
- Simultaneous ex-div and cum-div trading – a subset of shares have been traded simultaneously with the rights to receive the next dividend (cum-div), and without the right to receive that dividend (ex-div), but identical in all other respects. The difference in the prices of these shares is observed, and it is assumed that arbitrage will limit the extent to which traders can profit by buying one type of share and selling another (with transaction costs determining the arbitrage-free price range).
- Derivative prices – the price of certain types of derivatives (individual share futures are low exercise price options (LEPOs)) are observed and used to

767 This is ignoring efficiency gains that may come from changes to management or merging with other businesses.

768 More specifically, the point of interest is the time at which the right for the holder of a share to receive the next dividend is determined – typically referred to as the time at which shares go 'ex-div'.

make inferences about the different elements of the value or opportunity cost associated with the physical trading strategy that replicates the derivative. Arbitrage is assumed to imply that profits cannot be made by alternating between the future/LEPO and physical trading strategy, after taking account of transaction costs. For future/LEPOs, the physical trading strategy involves borrowing to purchase a share immediately, and paying back the loan at the maturity of the future/LEPO contract. As the holders of futures/LEPOs do not have rights to receive dividends (and franking credits), the implied value of franking credits (and cash dividends) can be obtained by examining the price of futures/LEPOs in the instances where dividends are expected during the term of the future/LEPO.

- Rights issues – where rights issues have different entitlements to the next dividend, either the prices of the existing shares and the new issue are compared and the value of the dividend and attached franking credits inferred by the price difference, or where the rights to new shares are renounceable (tradeable), the price of the right to purchase a share is compared to the price of existing shares and the subscription price, and the value of the dividend and attached franking credits implied by the price difference.

The empirical estimates of the value of imputation credits estimated by these methods that were presented in the Draft Decision were as follows.[769]

[769] In the Draft Decision, the changes of the tax law applicable to franking credits – and the implications of those changes – were also discussed: Draft Decision, p.264.

TABLE C.16

ESTIMATES OF THE VALUE OF FRANKING CREDITS

Study	Method	Study Period	Value of Credits
Hathaway and Officer (1999)	Aggregate taxation statistics	1989/90-1994/95	0.60
Hathaway and Officer (1999)[770]	Dividend Drop-off	1/1/1985-30/60/1995	Industrials: 0.61 Resources: 0.61 All Stocks: 0.63
Brown and Clarke (1993)[771]	Dividend Drop-off	1/7/87-28/5/88, 1/7/88-30/6/89 1/7/1989-30/6/1991	0.16 (0.18) 0.81 (0.80)
Brukner, Dews and White (1994)	Dividend Drop-off	1987-1990 1990-1993	0.335 0.688
Walker and Partington (1999)	Simultaneous ex div / cum div trades	1/1/1995-1/3/1997	0.88-0.96
Twite and Wood (2002)	Derivative prices	16/5/1994-31/12/1995	0.45
Cannavan, Finn and Gray (2002)[772]	Derivatives prices	May 1994-December 1999	Pre 45 day rule: 0.10 Post 45 day rule: -0.13 *Impact of rule: -0.23*
Chu and Partington (2001)	Rights issues	January 1991-December 1999	Almost fully valued
Chu, Lonegran, Partington, Stewart (2001)	Rights issue	January 1991-December 1999	Almost fully valued

Sources: Hathaway, N and R. Officer, 1996, The Value of Inputation Tax Credits, working paper, Melbourne Business School, p. 13 and table 1; Brown, P and A. Clarke, 1993, 'The Ex-Dividend Day Behaviour of Australian Share Prices Before and After Imputation', *Australian Journal of Management*, Vol. 18, table 7 and footnote 39; Bruckner, K. Dews, N and D. White, 1994, 'Capturing Value from Dividend Imputation', McKinsey and Company, quoted in Cannavan, D., F. Finn and S. Gray, 2002, 'The Value of Imputation Tax Credits', working paper, University of Queensland and Duke University, p. 14; Walker, S. and G. Partington, 'The Value of Dividends: Evidence from Cum-Dividend Trading in the Ex-Dividend Period', *Accounting and Finance*, vol. 39, p.293; Twite, G. and J. Wood, 2002, 'The Pricing of Australian Imputation Tax Credits: Evidence from Individual Share Futures Contracts', working paper, Australian Graduate School of Management, p.22; Cannavan, D., F. Finn and S. Gray, 2002, 'The Value of Imputation Tax Credits', working paper, University of Queensland and Duke University, table 41; Chu, H., G. Partington, 2001, The Market Value of Dividends: Theory and Evidence from a New Method, working paper, University of Technology, Sydney, p.39; Chu, H., W. Lonegran, G. Partington, R. Stewart, 2001, Dividend Values Implicit in Rights Prices, working paper, University of Technology, Sydney, p.22;

770 The estimates of the value of franking credit presented in the table allow for differences between the tax rate on capital gains and dividends (the formula derived in Brown and Clarke, 1992, and Walker and Partington, 1999, is used). The results are provided for the large capitalisation stocks only. The results for the small capitalisation stocks were erratic – a point also noted by Hathaway and Officer, p.18.

771 The figures in parentheses show the estimates when a dummy variable to control for the impact of the 1987 stock market crash is included.

772 The estimates of the value of franking credits before and after the introduction of the 45 day rule are only weakly significantly different from zero (10 per cent level of significance), whereas the reduction in the value of franking credits is strongly significant (1 per cent level of significance).

Professor Gray's comments on the various estimation methods suggest that, given the Commission's preference for an ownership benchmark that reflects an average investor in the Australian market, most weight should be placed upon the evidence from dividend drop-off studies. While the Commission discussed a number of empirical issues with dividend drop-off studies in the Draft Decision, it also considers that this method is the most widely used and accepted in Australia for estimating the value of franking credits. Professor Gray also noted a number of empirical issues with the studies using rights issues and simultaneous ex div / cum div trades, which the Commission has noted and taken into account, although these comments are of less significance given the comments above.

In the Draft Decision, the Commission stated that it was not convinced that it was appropriate to place *sole weight* on the recent working paper by Cannavan, Finn and Gray, as had been proposed by some of the distributors, but rather placed weight on all of the studies. The Commission's further consideration of the issue – in particular its consideration of the appropriate benchmark for the national identity of investors – confirms that placing sole weight on this study (which focuses on firms that have a large foreign ownership) is inappropriate. Having regard to the results of the empirical studies, and the matters discussed above, the Commission remains of the view expressed in the Draft Decision that 0.60 provides a reasonable estimate of the market value of franking credits once in the hands of investors.

As noted above, Envestra presented a late submission that included a detailed appendix on the assumption about the value of franking credits. None of the information sources referred to by Envestra were new, but the appendix nonetheless included substantial analysis that had not previously been presented, irrespective of the announced due dates for public submissions, and the Commission's announcements as to when it would need to receive material in order to give it full consideration.

Notwithstanding, the Commission has considered the late submission from Envestra, and has not been convinced that the material presented therein justifies a change to the assumption about the value of gamma, as discussed above. The appendix first challenged the Commission's assumption about the assumed proportion of franking credits that are distributed. As noted above, the Commission has relied upon Professors Officer and Hathaway's careful analysis of aggregate taxation statistics to derive this benchmark assumption, and does not consider Envestra's analysis to provide a superior estimate.

Envestra then challenged the assumption about the market value of franking credits once distributed. The only empirical estimate referred to was the study by Professors Officer and Hathaway noted above, with no reference being made to the other studies that the Commission referred to in the Draft Decision. The appendix referred to a discrepancy with the Commission's interpretation of that study, but did not disclose what the discrepancy was, nor the merits of the Commission's interpretation of that study. Envestra also questioned Officer and Hathaway's exclusion of small capitalisation stocks from their analysis. The Commission considers that it has interpreted the Officer and Hathaway study appropriately, also considers it desirable to place weight on the other studies summarised above and, regarding the exclusion of small capitalisation stocks, considers it more reasonable to rely on the judgement of Officer and Hathaway on this matter. Accordingly, the Commission does not consider Envestra's analysis to provide a superior estimate of the value of franking credits once distributed.

SEGREGATED-MARKETS CAPM VS INTEGRATED MARKETS CAPM

The Commission – in light of the comments and analysis of Dr Martin Lally – has discussed the implications of the segregated-markets and integrated-markets versions of the CAPM to illustrate the implications of consistency in the assumptions that are used to estimate the cost of capital. The main implication of the Commission's analysis has been to demonstrate that the arguments from the distributors in the current review (as well as in previous reviews) that foreign ownership implies a zero value for gamma should be assumed to imply that only the disadvantages suffered by foreign investors would be considered, with the advantages being excluded.

Notwithstanding comments to the contrary, the Commission has never suggested that foreign investment does not exist in Australia – clearly, this is inconsistent with what can be observed directly with no scope for debate. What the Commission has pointed out is that there are two versions of the CAPM, one of which assumes that the Australian capital market is separate from the rest of the world, and the second of which assumes that there is an integrated world capital market. Neither of these states are likely to be real: clearly there is foreign ownership of Australian assets (and Australian ownership of foreign assets). Equally, the evidence in support of the proposition that asset prices are determined solely with reference to an integrated world capital market is weak.[773] The problem is that there is no version of the CAPM for a world between these extremes. In his submission to the Draft Decision, Professor Gray commented that:

> First, none of the empirical papers cited by the Commission … find that franking credits are fully valued. Apparently foreign investors do exist. To assume them away, despite overwhelming evidence to the contrary, simply to preserve the theoretical purity of the chosen model is to move a long way from commercial reality.[774]

Given the discussion above, the Commission considers such a comment to miss the point.

773 One piece of vidence against the proposition that asset prices are determined with reference to an integrated world capital market is the observed significant home-bias in asset ownership.

774 Gray, S, Response to the Draft Decision, p.4.

The Commission has argued (in line with its analysis) that a move from a segregated capital market to an integrated one would be likely to imply a fall – and a substantial fall – in the cost of capital for Australian assets. This would reflect two factors – a fall in the equity premium because of the greater degree of diversification available in integrated capital markets, and a (possibly substantial) fall in the beta for Australian assets, as predicted by empirical estimates of equity betas for Australian firms against world share portfolios. While Australian franking credits would not be ascribed a value, the effects of the fall in the equity premium and beta would swamp the reduction in the gamma.

The implication drawn from this analysis was that, if all factors were taken into account, an increasing degree of foreign participation in the Australian market (and increasing degree of Australian participation in foreign markets) should reduce the cost of capital, not increase it. That is, the distributors' comments that increased foreign participation should be reflected in the gamma assumption but in no other assumptions – implying a rise in the cost of capital – were not plausible.[775]

The Commission also argued in the Draft Decision that the inputs that it had used to estimate the cost of capital assumed segmented capital markets. This is clearly the case for the beta assumption (as regard was only had to estimates of betas against home share markets) and considered the case for the equity premium and risk free rate. The assumption that clearly was not consistent with a segmented capital market was the gamma assumption. The assumption that franking credits once distributed are not fully valued must reflect foreign participation in the Australian market. Accordingly, it was concluded that, if absolute consistency with the theory were to be maintained, a lower estimate of the cost of capital would result.

As noted above, the submissions to the Draft Decision have challenged the Commission's observation that its other inputs into the cost of capital are consistent with segmented markets. The Commission does not accept some of these comments. For example, TXU and Multinet stated that the Commission:

> argued that there was no clear evidence that real interest rates have become lower as a result of internationalisation. This provides an example of the Commission dismissing evidence that is not consistent with its view of what should have happened.[776]

In fact, the Commission noted that the average real yield on bonds over the period between 1882 and 2001 was approximately 2 per cent, whereas the Commission had used 3.5 per cent as the real risk free rate in the Draft Decision (and has used 3.4 per cent in the Final Decision).

---

775 For the purpose of this analysis, the value of franking credits are expressed as being reflected in the cost of capital even though the Commission prefers to take account of their value through an adjustment to cash flows.

776 TXU, Response to the Draft Decision, Attachment D, p.22; Multinet, Response to the Draft Decision, Attachment C, p.21; Envestra, Response to the Draft Decision, p.51.

It was also argued that the levels of gearing assumed by the Commission might not be maintained in the absence of foreign capital flows. While this argument may be correct, it has little practical import: in that if franking credits are fully valued, the effect of the assumed level of gearing on the estimate of the cost of capital would be marginal at best. However, on a related issue, it is impossible to know whether the absence of foreign capital flows would imply a higher margin on debt. Equally, regarding the equity premium, the level of uncertainty associated with the estimation of the expected equity premium makes it impossible to prove or disprove whether the premium adopted by the Commission is affected by foreign participation in the Australian share market, or whether it is consistent with a segmented capital market.

In all of its decisions to date, the Commission has taken its best estimate of the equity premium and market value of franking credits, rather than to adopt an approach that would ensure absolute consistency with the underlying theoretical model, and this approach has been adopted again in this Final Decision. The Commission considers it an open question as to whether this 'part-foreign' model is likely overstate the cost of capital for the distributors' regulated activities. Hoever, the Commission remains of the view that the distributors' arguments that a zero gamma should be assumed in light of the substantial foreign participation in the Victorian gas distributors would imply that only the detriments suffered by foreign investors relative to domestic investors were recognised, but none of their benefits. It also remains of the view that the benefits available to foreign investors – the ability to obtain a greater degree of diversification, and the likelihood that the returns to Australian assets would have little relationship to the returns to their home market portfolio (and thus be considered to have little systematic risk) – are likely to be large.

Conclusion

The Commission confirms the estimate adopted in the Draft Decision that franking credits created are valued at 50 per cent of their face value. This reflects an assumption that approximately 82 per cent are distributed, and that the market value of credits distributed is approximately 60 per cent of their face value.

C.9 Excluded events

C.9.1 Background and distributors' proposals

As discussed in section C.1 above, while only the non-diversifiable portion of the risk affects an asset's cost of capital (ie. the return investors require on average), a second question that needs to be answered is whether the price controls generate the expected return. In principle, this implies that a view needs to be taken about whether all of the assumptions adopted in the setting of the price controls are unbiased forecasts. As well as judging the accuracy of all forecasts, this requires a view to be taken about the net impact of all events not explicitly considered when setting price controls.

In the 1998 decision, the Commission was convinced by the weight of submissions that the net impact of all excluded events was likely to be negative, and added an allowance in the price controls (through adding a margin to the WACC) to remove the perceived bias. The Commission explained its reasoning at the time as follows.

> [A] number of submissions pointed to the established practice of including some allowance in the cost of capital for non-systematic or diversifiable risks (such as regulatory risk and the risk of major infrastructure dislocations) which cannot be readily quantified and included in the cash flows, as the theory would require. The beta value selected by the [Commission] therefore consciously overcompensates investors for systematic risk, to recognise the existence of such diversifiable (or insurable) risks. In particular, the [Commission] has been deliberate in selecting a beta estimate near the upper bound of the plausible range to give appropriate weight to the risks that are perceived to be associated with the immaturity of the regulatory regime and the Victorian gas market reforms, and the presence of insurable risks such as those associated with possible major infrastructure disruptions.[777]

In its consultation papers prior to the Draft Decision, the Commission noted that since that decision, it has had the opportunity to analyse the question of the value of the net impact of excluded events in more detail. It pointed out that it had considered the issue during the recent review of the price controls for the electricity distributors, and decided that it would be inappropriate to include a positive allowance in respect of such events. This was based on its view, amongst other things, that the combined effect of the distributors' insurance policies and the limiting of exposure associated with a five-year regulatory period and carryover implied that the combined value of excluded events was likely to be immaterial. It also considered that there were offsetting positive events that also need to be taken into account.[778]

The Commission expressed the view that, as many of the issues related to electricity appeared equally relevant to gas, it did not consider there to be grounds for an *a priori* assumption that an additional allowance in respect of excluded events could be justified. That said, the Commission noted that the net value of any excluded events is an empirical matter, and invited the distributors to include any proposals and supporting information if they considered the methodology to be employed to determine expenditure benchmarks and forecast demand may lead to the expected return falling short of the estimated costs of capital.

During this earlier consultation, it was apparent to the Commission that there was a degree of confusion over the concept of diversification and its implications for the cost of capital (and for the determination of price controls generally). Likewise, there was confusion as to how the framework within which what has been referred to as 'excluded events' should be analysed. In response, the Commission provided a detailed explanation of the framework within which it proposed to analyse risk, including the intuition behind diversification, and principles that are relevant to the assessment of excluded events.[779]

---

777 Op. cit., 1998 Final Decision, p.75.

778 Op. cit., Consultation Paper No .1, pp.60-61.

779 Op. cit., Further Guidance to Gas Distributors, Appendix A.

This paper also provided a detailed discussion of the role of hedging in corporate finance, and the implications of hedging opportunities for the setting price controls for regulated entities. The Commission noted that, were it to take account of further hedging opportunities when assessing regulated charges, it is essential that the full implications of the additional hedging be taken into account. It noted that the rationale for greater hedging in commercial practice is that certain hedging may raise the value of a firm in the presence of particular types of market failure (such as costs associated with bankruptcy). An action that would raise the market value of an unregulated activity would imply lower regulated charges for a regulated activity. Thus, an assumption that further efficient hedging opportunities exist should lead to lower – not higher – regulated charges.

However, the Commission noted that the choice of an optimal hedging strategy is complex, and expressed a preference for adopting a simple benchmark for hedging arrangements based upon industry practice. It concluded that an important principle is to ensure that other benchmarks – such as the cost of debt and assumed gearing level – were consistent with the benchmark hedging arrangements.[780]

All of the distributors proposed the inclusion of an additional allowance in respect of excluded events in their operating expenditure, which they referred to as a 'self insurance' allowance. The amounts included were approximately $900 000 per annum for Envestra and Multinet, and $730 000 per annum for TXU. All three distributors submitted a substantially similar report from Trowbridge Consulting/Deloitte Touche Tohmatsu that quantified the value of negative excluded events.[781]

Multinet also proposed the inclusion of an allowance to cover the fair value of weather hedging. Such a hedge would insulate Multinet from the adverse financial consequences associated with warmer than average weather over the next regulatory period (or, more specifically, lower Heating Degree Days than the forecast used by VENCorp). Notwithstanding Multinet's proposal to be shielded from the adverse financial (revenue) consequences associated with warmer weather, it made no compensating adjustment to its demand or revenue forecasts when calculating its price controls.

The distributors also presented a number of qualitative arguments regarding the magnitude of the diversifiable association with gas distribution, including that associated with decisions of independent regulators and policy makers, as well as comments on the Commission's framework for analysing risk, and its view of the implications of greater hedging opportunities for the determination of price controls. The distributors argued that these qualitative arguments should be responded to by adopting conservative assumptions in the distributors' favour.

780 Op. cit., Further Guidance to Gas Distributors, Appendix A, p.57.

781 Trowbridge Consulting/Deloitte Touche Tohmatsu [Trowbridge Reports], Valuation of Excluded Events: TXU; Valuation of Excluded Events: Envestra; and TXU; Valuation of Excluded Events: Multinet.

C.9.2 Draft Decision

In the Draft Decision, the Commission concluded that, after considering the distributors' submissions in detail, the evidence the Commission considers to exist in relation to the 'positive' excluded events and the additional considerations raised by the distributors, the assumptions reflected in the price controls are unlikely to lead to a weighting that reflects anything other than the interests of the distributors. Rather, it concluded that the balance of the evidence would suggest that to the extent that there is 'asymmetry' in cash flows (such that the expected return differs from the estimated cost of capital), that asymmetry is likely to be weighted towards the interests of the distributors (that is, have a net positive value).

The Commission considered in detail the quantification of the value of the negative excluded events in the reports provided by Trowbridge Consulting/Deloitte Touche Tohmatsu (Trowbridge reports). The Commission noted that it considered those reports to provide a well-considered and thorough assessment of the likely adverse events that may affect the earnings associated with the Victorian distributors' regulated activities. However, it noted that when the estimates were interpreted in light of the totality of the regulatory arrangements proposed or accepted elsewhere in the Draft Decision, the cost of these events *to the distributors* would be unlikely to be material.

Two matters the Commission questioned in particular were the method used to determine the cost borne by the distributors should an adverse event occur, and the estimate of the expected cost associated with retailer default. With respect to the first of these, the Commission noted that the action of rolling-in expenditure and applying a carry-over would imply that the businesses would only be expected to bear approximately 30 per cent of the cost associated with an event, whereas the Trowbridge reports had assumed that the distributors would bear the whole of the expense.[782]

With respect to retailer default, the Commission noted that the estimates of the expected cost of this event assumed a high probability of retailer default, and that the distributors did not have arrangements in place to safeguard revenue. In contrast, the Commission noted that the terms and conditions it approved in the Draft Decision would permit the distributors to be substantially shielded from credit risk. Under these arrangements, the distributors would be permitted to obtain a bank guarantee for three months of charges if required to deal with a retailer that does not have an investment grade credit rating.[783] Thus, the distributors would either deal with retailers that have a low probability of default, or would have the option of requiring a bank guarantee to protect thier distribution revenue in the event of retailer default.

[782] In a later submission, Trowbridge confirmed that it assumed that the expenditure associated with such events would not be 'rolled-in' and excluded from the price controls (and so not give rise to double-dipping). The merits of this approach are discussed further below.

[783] In the Draft Decision, the exact requirement was investment grade credit rating or equivalent level of credit status. The Commission has accepted the consensus position of the distributors and retailers that a reference to investment grade credit rating alone is sufficient.

The Commission also noted that some of the elements included in the 'expected cost' estimates would be reflected more appropriately directly in expenditure forecasts. In particular, Envestra included an allowance for the future clean up of a contaminated site. The Commission noted that a preferable means of dealing with this event (as well as other similar events) would be to consider the cost associated with meeting the relevant legal obligation as part of the assessment of the expenditure benchmarks at the price review prior to the change in obligations occurring. The Commission also commented on several other items, which are addressed further below.

After adjusting for these items, the Commission concluded that the expected cost of such adverse excluded events would be expected to lower than submitted (somewhat lower than $200 000 per annum).

The Commission also discussed a number of potentially 'positive events' that it considered relevant. It referred to a comment in previous papers that utilities tend to outperform against regulatory benchmarks, and have the ability to lever-off the regulated activities into unregulated activities, which could be interpreted as 'positive events'. It also noted that the market values of utilities tend to exceed regulatory values, which supports the proposition that the net impact of the totality of assumptions adopted by regulators tend to be weighted towards the interests of regulated utilities. Lastly, the Commission noted a number of assumptions adopted in the Draft Decision that were considered conservative. It considered that the combined value of these excluded benefits would exceed the Commission's view of the expected cost of excluded adverse events.

The Commission also rejected Multinet's proposal to include an allowance in relation to the cost of purchasing a one-way hedge against unfavourable weather events in its operating expenditure.

It was noted that Multinet's proposal would result in it being able to avoid any financial consequences associated with adverse (warmer than average) weather, but continue to benefit financially from favourable (colder than average) weather. That is, Multinet's proposal would recognise only the cost associated with the hedge – but none of the benefits. It was noted that if an allowance were made for the cost associated with the one-way hedge, then it would also be necessary to deduct an allowance to remove the fair value of the benefit associated with that hedge, which would almost precisely offset the initial allowance. Given that the net effect of the two adjustments would imply no change to reference tariffs, the Commission considered the more practicable response to was reject Multinet's proposal.

The Commission also noted that Multinet's proposal appeared to reflect a misunderstanding of the Commission's general statements on the implications of hedging for assessing the price controls, as summarised above. Lastly, the Commission noted that, to the extent that significant benefits from the removal of weather-related volatility in revenue were expected, a lower cost means of removing this volatility would be to consider other forms of price control – such as a hybrid control with a large fixed element, or a revenue cap.[784]

[784] These forms of price controls were discussed in: Office of the Regulator-General, Consultation Paper No. 3, The Form of Price Control, 2001 Electricity Distribution Price Review, December 1998.

C.9.3 Responses to Draft Decision

Trowbridge Consulting/Deloitte Touche Tohmatsu provided a submission clarifying the basis for the reports they prepared on behalf of the distributors, and responding to the comments made by the Commission. Trowbridge commented that their approach was designed to address the concern that the distributors may have a perverse incentive to over-insure if expenditure benchmarks include an allowance for insurance premiums paid, but not for the expected costs of uninsured events. It was also noted that offseting the cost of the negative excluded events with the benefit from positive events would not remove such a perverse incentive. Finally, they noted that while data was scarce in many cases, requiring judgment to be exercised, their estimates were considered to be best-estimates.

Trowbridge also addressed a number of the Commission's specific comments, including:

- Credit risk – it was not considered appropriate to use a parent company's credit rating in the analysis, and regardless, the Commission had understated the default and recovery rates of BBB firms;
- Supply disruption and machinery / equipment failure – it commented that it did not consider the amounts to overstate the expected cost of the relevant event;
- Key person risk – it confirmed that the loss of network and company specific expert staff would be adverse to earnings; and
- Contaminated sites – it confirmed that it considered it appropriate to make an allowance for this event, and that allowing for the time value of money would represent spurious accuracy.

It also noted that it had not quantified other risk – such as regulatory risk – which may be significant.

Envestra referred to the Trowbridge comments, and argued that its allowance of $1 million remains appropriate. It commented that it did not agree with the Commission's view that it had been conservative in the assumptions adopted in the Draft Decision. It backed this claim by referring to the Commission's treatment of working capital, its assumption that reported costs are efficient, not recognising the increase in insurance premiums in the operating expenditure benchmarks, and assumption that the distributors could achieve greater productivity improvements than the economy as a whole.[785] In a subsequent submission, TXU also endorsed Trowbridge's comments.[786]

[785] The issue of the appropriate productivity assumption is addressed in section 3.3, and is not commented on further below.

[786] TXU, Further Response to the Draft Decision, 23 August 2002, p.2.

TXU and Multinet questioned the evidence that regulators tend to err towards the interests of the regulated businesses, questioning the Commission's conclusion that it had been conservative in the Draft Decision. They noted that drawing inferences from the out-performance of the distributors against regulatory benchmarks may weaken the incentives to be efficient (that is, by implementing an implicit 'claw-back' of previous gains). On the market value of the regulated activities, it was noted that if regulators were conservative when setting price controls for regulated utilities, the 'Tobin's Q' ratio for these firms would be greater than the market average – adding that they were unaware that any such evidence existed. They also noted that if the cost of capital assumed by the regulator was too high, then the distributors would gold-plate – and that there was no evidence of this.[787]

With respect to the Draft Decision itself, TXU and Multinet commented on the assumption with respect to productivity improvements in the gas industry:

> Given the Commission's assumption that the industry is already efficient and given the pace of technological change in the gas distribution sector, it is difficult to conceive how it could be assumed that efficiency improvements in this sector of the economy could be greater than those of the entire economy. Indeed, because productivity growth in the gas distribution sector is likely to be lower than that of the economy generally (and the economy wide productivity improvements are already captured in the CPI generally), then the assumed productivity growth should be at least zero and could be more than zero (ie. 'X' in the true CPI-X formula would be negative).[788]

Neither presented any empirical evidence on productivity trends in gas distribution to support these statements.

All three distributors commented that the Commission had not addressed regulatory risk in the Draft Decision, commenting as follows:

> The Commission continues to ignore regulatory risk despite the distributors' efforts to encourage the Commission to address it. Indeed, the Commission's entire Draft Decision (some 308 pages) is completely devoid of the terms "regulatory risk" or 'regulatory certainty'.[789]

The decisions giving rise to regulatory risk were claimed to include:

- the move from a pre-tax to post-tax approach;
- the reduction to the equity beta;
- casting doubt on the future use of the CAPM;
- applying a high burden of proof to the distributors' proposals;
- assuming that the distributors are efficient, but also suggesting that they could improve efficiency faster than the economy as a whole; and

---

787 TXU, Response to the Draft Decision, Attachment D, pp.5-9; Multinet, Response to the Draft Decision, Attachment C, pp.6-9.

788 This matter is addressed in section 3.3, and is not commented on further below.

789 Envestra, Response to the Draft Decision, p.53. The other distributors made a comment in substantially similar terms.

- referring to strategic behaviour on the part of the distributors.[790]

Regarding volume risk, TXU and Multinet made a number of comments about the consistency of the Commission's treatment of hedging, the Commission's comments about the implications for prices of hedges, and consistency with electricity retail and distribution, concluding that:

> [The Commission] has not demonstrated how it has taken account of volume risk in its estimate of the cost of capital, nor in its conservative approach.[791]

KPMG (for the Australian Gas Association) also commented on the role of hedging in its submission. Its argument appeared to be that higher regulated charges (that implied by a CAPM-derived return) should be set because this will reduce the likelihood that the distributors will hedge (or insure) against all adverse events (because, with greater free cash flow, adverse impacts could be more easily absorbed). By encouraging less hedging, the incentives to be efficient will be larger. In KPMG's words:

> prices or revenues should be struck at a level that provides management with sufficient incentive for efficient, value-adding risk taking[792]

KPMG (for the Australian Gas Association) also discussed the Commission's comments on the sources and indicators of positive excluded events, particularly the Commission's observation that companies tend to outperform, and the Commission's observation about the relationship between market and regulatory values. These matters are discussed in section C.7.

Finally, Envestra repeated an example in its original submission that showed how a threat to disallow capital expenditure creates an expected loss.[793]

C.9.4 Further analysis

This section addresses the specific comments regarding the quantification of the expected cost of adverse events by Trowbridge Consulting/Deloitte Touche Tohmatsu, and then addresses the other matters raised by the distributors.

---

[790] All distributors also referred to the erroneous statement in the Draft Decision about a potential future reduction of equity returns. This matter was addressed in section 3.6.

[791] TXU, Response to the Draft Decision, Attachment D, p.26; Multinet, Response to the Draft Decision, Attachment C, p.24-25.

[792] KPMG, AGA Sub, p.9.

[793] Envestra, Response to the Draft Decision, pp.53-54.

Quantification of the expected cost of adverse events

In the Draft Decision, the Commission noted that it considered the Trowbridge Consulting/Deloitte Touche Tohmatsu reports (Trowbridge reports) to provide a well-considered and thorough assessment of the potential financial consequences of the adverse events that could affect the Victorian gas distributors. As well as informing the current regulatory process, the Commission would expect that the greater understanding of these matters would assist the distributors in the development of their own strategies to mitigate the likelihood, or to ameliorate the consequences, of such events. However, the relevance of the material to the Commission is limited to whether recognising such events should lead to a materially different set of price controls for the distributors. Importantly, the weight to be placed on such events needs to be considered in the context of the totality of the regulatory arrangements.

Two separate issues were raised in the response of Trowbridge to the Commission's Draft Decision related to:

- whether in the absence of a provision for self-insurance, the distributors would have a perverse incentive to over-insure; and
- the Commission's comments on the expected costs of these events as estimated by Trowbridge.

Regarding the first of these matters, the Commission is not convinced that the potential for a perverse incentive to over-insure is sufficiently large to warrant the application of a self-insurance premium. Nor is it convinced, even if such an incentive existed, that the provision of a self-insurance premium would be the best means of addressing such an incentive.

This Final Decision will result in new reference tariffs that apply for five years, the distributors stand to gain during the period from an efficient choice between insurance and self-insurance. Any over-insurance would not be expected until late in the period, and be short-lived. It is also noted that a perverse incentive to over-insure can only exist where commercial insurance for the particular event is available at reasonable cost, whereas a theme throughout much of the Trowbridge reports was that insurance is not available for many of the events identified. Lastly, the distributors' current spending on insurance policies and the quantum estimated for a self-insurance premium would suggest that the magnitude of any perverse behaviour would be small in the context of the distributors' overall operation, particularly when compared to the administrative costs that would be incurred in estimating and re-estimating self-insurance premia at successive reviews.

Regarding the design of the mechanism, the Commission notes that many of the estimates of the expected cost of adverse events were based largely on judgement, given the absence of rigorous data on the frequency of these events, something that Trowbridge clearly acknowledged. However, a similar level of uncertainty is likely to exist at future reviews, making it difficult to conclude that any future promise of such an allowance would lead to a material change in the businesses insurance purchases.

Regarding the Commission's comments on Trowbridge's estimates of the expected cost of these events, the Commission notes that its views on the two material issues related to interpretation of the events *in light of the overall regulatory framework* applicable to the distributors, which was a different context to that assumed by Trowbridge. The first issue related to the share of the cost associated with an adverse event that would be borne by the distributor (rather than customers), and the second related to the extent to which the distributors would be exposed to counter-party credit risk.

Regarding the first issue, the Commission's assumption was that capital and expenditure in respect of such events would be included in the distributors' capital bases at the next price review, and that capital and operating expenditures would be taken into account in determining a carryover amount. In contrast, Trowbridge's assumption was that the distributors would bear the expenditure associated with an excluded event, and hence it would be quarantined from the capital base and reported operating expenditure.

The Commission remains of the view that it would be undesirable to attempt to quarantine expenditure on excluded events from the distributors' expenditure on the remainder of their activities. In practice, it is likely to be difficult to determine the precise share of expenditure that is attributable to excluded events. Whether an event is an 'excluded event' may be difficult to determine given that it is impossible to determine an exhaustive list for such events in advance. In addition, even once an excluded event is identified, at least a part of the response to an event would be a diversion of resources from other activities. Moreover, the Commission does not consider that it is necessary to expose the distributors to the full consequences of excluded events, in order to encourage the distributors to take steps to reduce the likelihood or consequences of such an event. Rather, the Commission considers that the 30 per cent share of the consequences is implied by the incentive arrangements discussed in section 3.8 would provide sufficient incentive.

Accordingly, the Commission will not seek to quarantine the expenditure related to such events from the remainder of the distributors' expenditures, and so remains of the view that the adjustments it made to Trowbridge's calculations in the Draft Decision are appropriate.

With respect to exposure to counter-party credit risk, the Commission notes that its comments in the Draft Decision were based on the assumption that the distributors would be significantly shielded from this risk (as the distributors had proposed in their terms and conditions), whereas Trowbridge had assumed that the distributors would be exposed. The Commission remains of the view that it is appropriate for the distributors to be substantially shielded from this risk, and has approved terms and conditions to this effect. Accordingly, the Commission remains of the view that a downward revision to the estimates provided by Trowbridge is appropriate.

Regarding Trowbridge's comments on the appropriate size of the adjustment that is appropriate, the Commission also remains of the view that the assumptions it adopted are appropriate. The Commission's views on the two matters raised are as follows.

- Ability for retailers to have access to parent company credit ratings – the Commission notes that if is not guaranteed by a parent (and does not have an acceptable credit rating of its own), then the distributors would be able to require a bank guarantee, and thus be substantially shielded from the consequences of retailer default.

- Default rates – the Commission has used the default rate applicable to BBB firms that go immediately into liquidation in its analysis. Trowbridge commented that BBB firms tend to suffer ratings downgrades before going into liquidation, so that the default rate of BBB firms that eventually go into liquidation is much higher than the rate assumed by the Commission. While this observation is correct, the Commission notes that the terms and conditions permit the distributors to require a bank guarantee as soon as a retailer loses an investment grade credit rating, and thus become substantially shielded from the consequences should that retailer eventually default. Hence, the rate of BBB firms that go immediately into liquidation is the relevant rate default rate. The same arguments apply with respect to the recovery rates.

Accordingly, the Commission remains of the view that the adjustments it made in the Draft Decision to Trowbridge's estimates of the expected cost associated with retailer defaults were appropriate.

More generally, the Commission considers that, where possible, a preferred means (and, in the case of some of the risk that is within the control of the distributors, the prudent means of addressing that risk) is to eliminate the risk. One of the adverse events referred to in the Trowbridge report related to a change in safety requirements by the Office of Gas Safety during the regulatory period. However, the Commission facilitated a process between the distributors and the Office of Gas Safety during the assessment of the distributors' expenditure proposals, specifically to reduce the likelihood of such an event during the regulatory period. In addition, to the extent that a change in mandated requirements occurs during the regulatory period, then there may be scope for distributors to pass-through the resultant increase in costs immediately under their change in tax pass-through clauses (this issue is discussed further in section 4.8).

The Commission also commented on the magnitude or relevance of key person risk in the Draft Decision. While the Commission questioned whether there could be any significant loss of earnings associated with the regulated activities if a commercial manager departed, it accepts that the loss of key technical personnel could be disruptive if they hold significant corporate knowledge on the system that is not shared by others. However, rather than bear such a risk (and hope that the event does not occur), the Commission would expect that a prudent distributor would take actions to remove such a risk, particularly given the significant safety issues associated with gas distribution.

Given the further consideration of this issue as set out above, and the observations made in the Draft Decision, the Commission remains of the view that the expected costs of the potentially excluded events associated with the provision of regulated gas distribution in Victoria are unlikely to be sufficiently material to justify an additional allowance. In the Draft Decision, the Commission commented that the impact of all such events was likely to be no more than approximately $200 000 for each distributor. Its further consideration of the scope for the elimination (rather than compensation) of risk in this Final Decision suggests that a further downward revision to this figure is warranted.

In addition, the Commission remains of the view that it has made a number of conservative assumptions in this Final Decision that amount to positive excluded events, and that the value of these positive events would more than offset the negative events discussed above. Lastly, it also remains of the view that the objective evidence it discussed in the Draft Decision lends weight to the conclusion that, on the whole, regulators tend to err towards the interests of regulated businesses.

Accordingly, the Commission affirms its view in the Draft Decision that it would be inappropriate to make an additional allowance in respect of negative excluded events.

In the Draft Decision, the Commission noted that Envestra had proposed a self-insurance allowance in respect of a possible future requirement to remediate a contaminated site. While TXU and Multinet did not include a similar provision in their self-insurance allowance, they included such an event within the scope of their change in tax pass-through clauses.

Since the Draft Decision, the Commission has considered further the issue of whether the distributors should be permitted to recover the cost associated with the remediation of contaminated sites from customers. One view, which the Commission considers has merit, is that the distributors accepted the liability associated with the remediation of these sites as part of their contracts with the Government in 1999, and that the costs should be borne by the businesses. However, the Commission is not required to make a decision on this matter at this stage, and intends to consult further as to the proper interpretation of such an obligation to clean-up these sites in the future, should such an obligation be imposed. The Commission does not therefore consider it appropriate for an allowance for such an event to be reflected in a self-insurance allowance, and does not consider that such an event should be within the scope of the change in tax pass-through clauses.

Volume risk

In their responses to the Draft Decision, both TXU and Multinet made a number of statements about the Commission's treatment of 'volume risk' and the related issue of the role of hedges in the assessment of price controls that appear to reflect some misunderstanding of the comments made in the Draft Decision. The Commission addressed the issue of hedging at length in a previous consultation paper,[794] including many of the matters that have been raised once more in the submissions to the Draft Decision. The Commission retains the views expressed in that paper, with statements made by TXU below:

> In relation to volume risk, the Commission now argues that:
>
> - volume risk imposes no costs on the businesses (either in terms of gearing, debt costs etc,); and
> - passing the volume risk to customers via a new form of price control would result in a more efficient outcome.
>
> These two positions remain impossible to reconcile.[795]

The Commission has neither argued that volume risk does not impose costs on the businesses, nor has it argued that 'passing the volume risk to customers' would be more efficient.

With respect to the first of these points, the Commission has acknowledged that variation in cash flow may impact on the level of debt that a firm may maintain and/or its cost of raising debt finance.[796] However, the Commission has emphasised that the implication of this observation is that there must be *consistency* between the hedging assumptions that lie behind the benchmark financing arrangements, and the hedging assumption reflected in benchmark revenues.[797] The Commission has commented that the Australian utilities that form the basis of the benchmark financing arrangements do not undertake significant hedging activities apart from standard interest rate risk management.[798] Accordingly, consistency with this benchmark financing arrangement would imply not including allowances for hedging activities.

---

794 Further Guidance, Appendix A.

795 TXU, Response to the Draft Decision, Attachment D, p.26; Multinet, Response to the Draft Decision, Attachment C, p.24.

796 Further Guidance, p.56.

797 Further Guidance, pp.57-58.

798 Further Guidance, pp.57-58.

With respect to the second of these points, the Commission noted in the Draft Decision that if weather hedging was 'efficient', then a lower cost method of hedging could be achieved through a change to the form of price control (ie by reducing the relationship of revenue to energy usage).[799] However, the term 'efficient hedging' was used to refer to the type of hedging that would raise shareholder value (ie the benefits through the reduction in market imperfections would exceed the cost of the hedge). No comment was made as to whether hedging against revenue volatility would be efficient hedging.[800]

TXU and Multinet also commented that:

> The Draft Decision maintains the view that hedging would lower prices.[801]

However, they did not offer an opinion as to whether or not hedging would lower prices. It was merely noted that efficient hedging (as defined above) would imply lower prices if the benefits as well as the costs of hedging were taken into account. The Commission stated that it would retain its simple benchmark that the distributors undertake no hedging (and with benchmark financing assumptions consistent with this). Thus, if efficient (ie. shareholder value improving) hedging opportunities existed, then the distributors would obtain the benefit of this.

Further, TXU and Multinet commented that:

> The Draft Decision also fails to explain why the Regulator was prepared to include hedging costs when reviewing electricity retailer costs, notwithstanding the position it has adopted in relation to the treatment of similar risk in the gas distribution sector.[802]

The Commission has already addressed this issue expressly.[803] In brief, virtually every electricity retailer enters into electricity price hedges, and so the benchmarks to which the Commission had regard (such as margins) would reflect this hedging activity. Accordingly, consistency required the recognition of hedging arrangements.

Lastly, TXU and Multinet commented that:

> The Draft Decision's benchmark costs for the gas distributors assume no hedging and they provide the same benchmarks for electricity and gas, even though it has been demonstrated that revenue risk for the gas distributors is much higher than for the electricity distributors.[804]

---

799 Draft Decision, p.280-281. It was also noted that the tariff basket form of price control – which has been adopted for the second regulatory period – should lead to a reduction in the volatility of revenue.

800 Draft Decision, p.280.

801 TXU, Response to the Draft Decision, Attachment D, p.26; Multinet, Response to the Draft Decision, Attachment C, p.24.

802 Draft Decision, p.280.

803 Further Guidance, p.58, footnote 132.

804 TXU, Response to the Draft Decision, Attachment D, p.26; Multinet, Response to the Draft Decision, Attachment C, p.24.

The Commission has determined its benchmark financing arrangements with reference to listed Australian utilities, the majority of which are gas companies. Moreover, the utilities that have very few unregulated activities – Envestra and GasNet – are both gas utilities, and both have gearing levels well in excess of the Commission's benchmark assumption. Accordingly, the Commission considers that its benchmark financing arrangements are consistent with the revenue volatility of regulated gas distributors. Regarding compensation for volume risk, the Commission notes that, to the extent that volume risk is systematic that is reflected in the proxy equity beta, and to the extent that it is diversifiable, it is irrelevant. Accordingly, the Commission considers that it has taken account of volume risk in this Final Decision.

KPMG comments that higher prices need to be set so that firms do not over-hedge are considered not to have any merit. First, it is unclear whether a rise in revenue would lead to a change in the businesses financing/hedging decisions. As the distributors are free to adopt whatever financing arrangements, a rise in revenue may just lead to an adjustment to debt levels to restore the desired gearing level, with no change to the ability to absorb the consequences of adverse events, and thus the same demand for hedging/insurance.

Second, exposure to the consequences of events can only improve efficiency if the distributor has some control over the likelihood or severity of the event. However, it is for these types of events that 'moral hazard' is a concern – and so hedging or insurance would either not be available or, if available, would be subject to terms designed to ensure the distributors have an incentive to minimise an event's incidence or severity.

Third, it is not at all clear what types of hedges that KPMG is concerned to ensure that the distributors avoid purchasing, and it is not clear that such products are even available. As the Commission has commented above, Australian regulated energy distributors do not undertake significant hedging opportunities outside of standard interest rate risk management. Therefore, it would be difficult to conclude that KPMG's argument had practical merit even if it had theoretical merit (which is not considered to be the case). Lastly, KPMG's views appear to be affected by its understanding that the CAPM provides an estimate of the *minimum* return required by investors. This is wrong: the required return that is estimated by the CAPM is the expected (ie average) return.[805]

Apart from the matters above, Multinet did not comment expressly on the Commission's statements in the Draft Decision regarding Multinet's proposed allowance for the cost of weather hedging. The Commission therefore confirms its view that such an allowance would be inappropriate for the reasons summarised above and set out in more detail in the Draft Decision.

---

805 As noted above, Appendix A of the Commission's Further Guidance paper set out in detail the Commission's views on the mainstream analysis of risk and the relevance of hedging opportunities with that framework. That appendix, in large part, was a response to an earlier submission by KPMG entitled Treatment of Business Risks (October 2001). Many of the comments the Commission made in Appendix A of the Further Guidance paper are equally applicable to the most recent KPMG submission.

Regulatory risk

As noted above, the distributors also referred to what they considered to be significant ‘regulatory risk’ associated with the regulatory regime applicable to the Victorian gas distributors, and advocated that this be taken into account when assessing price controls (the route suggested was by adopting more conservatism with respect to the equity beta). The distributors also stated that the Commission had ignored regulatory risk in the Draft Decision. While the Commission considers that the assumptions it has made with respect to the cost of capital (and equity beta in particular) are conservative – and therefore are consistent with the distributors’ proposals – some remarks on these comments follow.

Addressing the latter of these comments first, the Commission does not accept the comment that it had ignored the adverse effects of uncertainty associated with regulatory decision making in its Draft Decision. Rather, the Commission has endeavoured in its various decisions to provide as much certainty as possible and appropriate, as to the future exercise of its discretion. Indeed, the Draft Decision included a range of components that were designed expressly to reduce the level of uncertainty, that have been further expanded in this Final Decision. Some of the measures to reduce this uncertainty that the Commission has accepted or put in place include the following:

- Stranded asset risk and regulatory depreciation – the Commission has accepted a fixed principle not to seek to identify and remove stranded or partially stranded (redundant) assets, and has accepted (or offered) this protection for 30 years. This commitment not to strand assets is a legally binding commitment. The Commission has also invited the distributors to bring forward the recovery of capital if they consider that future developments may reduce their ability to recover their investments through regulated charges.

- Prudence/efficiency tests – the Commission has not sought to judge the prudence or efficiency of capital or operating expenditure, but rather has inferred that well-designed incentives will deliver this result. That is, it has not exercised the power to disallow expenditures, and has put in place a framework of incentive regulation that should obviate the need to consider disallowances in the future.

- Efficiency carryover – the Commission has approved detailed principles for the calculation of a carryover amount at the next review.

- Pricing – the Commission has approved a price control formula that provides the distributors with greater discretion over tariff setting.

- Licence fees – the Commission has approved a price control formula that largely insulates the distributors from the uncertainty associated with licence fees, and which will also permit the foreshadowed increase for the financial year 2001-02 to be recovered.

- Cost of capital – the Commission has made transparent the assumptions upon which the cost of debt is estimated and confirmed its previous practice of deriving the risk free rate with reference to objective market data.

- Cost of tax – the Commission has approved a fixed principle ensuring that the method that has been used to derive a benchmark tax allowance continues to be used for the next 30 years.
- Recovery of FRC costs – the Commission has approved a fixed principle that will ensure that costs approved under the FRC Order in Council that have been unrecovered at the end of the 2003-07 access arrangement period, or which relate to continuing activities, are taken into account in the assessment of reference tariffs at the next review.

The Commission considers that the combined effect of these measures should substantially reduce the uncertainty associated with future regulatory decisions. However, it notes that further refining the regulatory approach over time is inevitable and desirable in light of experience, additional information and innovation in the practice of regulation, but which needs to be weighed against the likely benefits to all parties from stability. However, the Commission does not accept that it is inevitable that all such innovation will be to the detriment of the distributors and indeed, that many of the measures discussed above unambiguously weigh towards the interests of the distributors (as well as customers) over the long term.

C.9.5 Conclusion

The Commission does not consider that an additional allowance in respect of potentially excluded events, or in respect of the fair-value of entering into weather hedges, is warranted.

Appendix D The building block approach and working capital

D.1 Gas Code requirements

Regarding working capital, neither the Gas Code nor the legislation that provides it with legal effect explicitly refers to working capital.[806] Accordingly, the relevant guidance on this matter is in the objectives for reference tariffs set out in section 8.1 of the Gas Code, reconciled and weighted having regard to the factors set out in section 2.24, and the requirements of section 8.2.

Regarding the technical formulation used to derive revenue benchmarks, section 8.4 of the Gas Code describes three approaches that may be used namely:

- Cost of service approach – target revenue is calculated on the basis of a return on the value of capital assets, depreciation and operating, maintenance and other expenses;
- Internal Rate of Return (IRR) approach – target revenue is a forecast of all costs to be incurred during the period with capital costs derived from the difference between the capital base at commencement of the relevant period and residual value at the end of the period; and
- Net Present Value (NPV) approach – target revenue is calculated by finding the amount of revenue that would deliver a present value of future revenue (and the residual value at the end of the regulatory period) equal to the regulatory value of the assets at the start of the period, where the discount rate is commensurate with the prevailing conditions in the market for funds and the relvant risk involved.

Section 8.4 of the Gas Code also provides that the methodology used to derive the Cost of Service, NPV or IRR should be in accordance with generally accepted industry practice.

D.2 Background and distributors' proposals

The Commission did not address the issue of working capital in its 1998 decision and did not factor any allowances in relation to working capital into the reference tariffs.

806 Interestingly, even Attachment A to the Gas Code, which is a detailed list of the cost items that may be taken into account when assessing reference tariffs, makes no reference to working capital.

In consultation prior to this review, the Commission discussed the guidance provided by the Gas Code on working capital. In particular, it noted that an appropriate means of reconciling its statutory guidance is to ensure that reference tariffs provide an allowance equal to the assumed opportunity cost of funds for the timing difference between the receipt of revenue and the occurrence of costs, irrespective of whether specific expenditure items are classified as operating or capital expenditure.[807] This is equivalent to stating that reference tariffs should be calculated to provide a 'net present value' of zero, given the Commission's assumptions about expenditure, demand and the cost of funds.[808]

The Commission also noted that any target revenue formula makes an implicit assumption about the timing of cash flows *within each year*, which would inevitably reflect a simplification of the true timing of cash flows. Under this analytical framework, including an allowance in relation to working capital is equivalent to arguing that the implicit timing assumptions *in relation to operating activities* may not reflect the true timing of that subset of cash flow within a given year, and so may understate the opportunity cost associated with investors' funds. However, the Commission noted that considering the implicit timing assumptions with respect to operating activities alone is only part of the issue. Given the analytical framework discussed above, it noted that the relevant issue is whether the implicit timing assumptions for *all of the forecast cash flow* within any year would provide a reasonable proxy for the true timing of that cash flow. This is equivalent to asking whether the reference tariffs provide a net present value of zero for the regulated activities[809] when taking into account the timing of cash flow *within each year*.[810]

Regarding section 8.4, the Commission noted that the *NPV* and *IRR* approaches are alternative means of aligning the present value of revenue and cost – in effect, mathematical transformations, where the same inputs are used. It also noted that the *Cost of Service* approach could be demonstrated to be merely a rearrangement of a present value calculation, and thus deliver the same results where there is a common set of assumptions.[811]

Ignoring company tax and inflation, the Commission proposed the use of the following formulation of the simple target revenue formula:[812]

$$\text{Target Revenue}_i = \text{WACC x Average Asset Value}_i + \text{Depreciation}_i + \text{O\&M}_i$$

807 Op. cit., Consultation Paper No. 1, pp.68-69; Position Paper, pp.47-48; Further Guidance to Gas Distributors, pp.43-44.

808 The 'net present value' associated with the regulated activities will only be zero if the Commission's assumptions are unbiased forecasts of those inputs. As the Commission has adopted a conservative approach with respect to many of the inputs, the 'true' net present value associated with the income from the regulated activities would be expected to exceed zero.

809 Note the caveat mentioned in footnote 808.

810 This implies discounting cash flow on a weekly or daily basis rather than on an annual basis.

811 The analytical link between accruals and cash flow concepts for both regulatory and accounting purposes, and the relevant academic literature, is discussed in Johnstone, D, *Replacement Cost Asset Valuation and Regulation of Energy Infrastructure Tariffs: The Problems with DORC*, Department of Accounting and Finance, University of Wollongong, 2001, pp.6-7.

812 Op. cit., Consultation Paper No. 1, p.69.

Given this formula, the Commission noted that it is an empirical matter as to whether the implicit timing assumptions provide a reasonable proxy for the true timing of that cash flow (that is, whether it delivers a 'net present value of zero).[813] However, it noted that its analysis of the within-year timing of revenue and costs for the Victorian electricity distributors found that any bias in the above formula was likely to be weighted towards the interests of the electricity distributors. This suggests that the simple formula is likely to understate the revenue required given the actual timing of the distributors 'revenue and costs.[814]

The Commission clarified that its analysis did not show that the Victorian electricity distributors would not have a working capital requirement, but rather that the electricity distributors would, on average, incur operating expenses before receiving revenue. However, this analysis also showed that any bias against the distributors from omitting the financing cost associated with operating activities was swamped by positive bias caused by the favourable timing assumptions implicit in the calculation of the capital-related components of target revenue.[815]

In submissions to this review, neither TXU nor Multinet sought an allowance in relation to working capital. Multinet noted that its analysis of the within-year timing of its cash flows suggested that there was unlikely to be a material bias in either direction.[816]

In contrast, Envestra proposed a significant allowance for working capital for its Victorian system of $1.1 million in 2003, rising to $1.4 million in 2007.[817] In doing so, it made a number of arguments in favour of including a working capital allowance and referred also to decisions of other Australian regulators that included such an allowance (namely the QCA, IPART and the WA Independent Gas Pipelines Access Regulator).

Envestra also commented that the Commission's approach for analysing the issue of working capital is biased against the distributors, pointing to an (allegedly) technical error in the Commission's methodology.[818] It also commented that the use of 'within year' discounting is 'inappropriate for regulatory price determinations as it is not accepted business practice' and therefore inconsistent with section 8.4 of the Gas Code. Envestra queried the Commission's reasoning for changing the target revenue formula from that adopted in the 1998 review.[819]

813 Note the caveat in footnote 808.
814 Op. cit., Further Guidance to Gas Distributors, p.43. Both TXU and the Multinet's advisers were party to the Commission's analysis of the timing of the Victorian electricity distributors' cash flow, and the Commission has provided and explained its analytical approach to Envestra.
815 Op. cit., Further Guidanc to Gas Distributors, p.43.
816 Multinet, Access Arrangement Information, p.53.
817 Envestra, Access Arrangement (Victoria), Working Capital Submission, p.2.
818 ibid.
819 Envestra, Access Arrangement Information, p.C4.

D.3 Draft Decision

In the Draft Decision, the Commission reaffirmed its view that the framework described above for analysing proposals for an allowance in relation to working capital is appropriate. That is, in light of the guidance provided by the Gas Code the relevant issue is whether the implicit assumptions in the simple target revenue formula about the timing *of all the forecast cash flow* within any year provides a reasonable proxy for the true timing of that cash flow. As discussed above, this can be restated as implying that the net present value of cash flow associated with the regulated activities is zero, given the cost of capital, expenditure and demand assumptions adopted by the Commission.[820] This is referred to below as the 'net present value' approach.

The Commission also addressed Envestra's argument (and evidence) that working capital requirements are common across industries. In doing so, it noted that it had never stated that the distributors would not have working capital requirements, but rather that its analysis of the electricity distributors suggested that they would be expected to have a working capital requirement.[821] Rather, the Commission's analysis suggested that any financing cost associated with operating activities would be more than offset by the favourable timing assumptions implicit in calculating the capital-related components of target revenue.

The Commission noted that it had responded to Envestra's comments about 'regulatory precedents' in its previous consultation papers.[822] Specifically, it observed that other regulators had adopted varied approaches to this issue. While the regulators that Envestra referred to have provided allowances in relation to working capital, the ACCC – which regulates every covered transmission pipeline in Australia (except those in Western Australia) – has adopted the Commission's approach. The Commission also responded to Envestra's reference to the practice of the UK energy regulator (OFGEM) in a previous paper by noting that Envestra's example referred to that regulator's approach with respect to *retailers*. In contrast, it has not been OFGEM's practice to include an allowance for working capital in assessing price controls for *distributors*.[823]

The Commission also examined Envestra's comment that the Commission had erred in applying the analytical framework discussed above. In doing so, it expressed the view that there was no error in the method by which the Commission applied its analytical framework and that Envestra's comments appeared to reflect some confusion about the discounting of cash flows. It also noted that Envestra had incorrectly asserted that the 'implicit assumption is that cash flows are spread evenly throughout the year'. Rather, the implicit within-year timing assumptions under the Commission's simple target revenue formula are that:

---

820 Note the caveat in footnote 808.

821 Draft Decision, p.109. The results of the Commissions analysis are in: Op. cit., Electricity Distribution Price Determination 2001-05, Volume 1, p.116. The implicit cost of financing operating expenditure is shown in the column entitled 'Operating Expenditure Only' in table 6.3.

822 Draft Decision, p.110.

823 Further Guidance to Gas Distributors, p.44.

- half of the annual depreciation allowance is received and half of the annual capital expenditure is undertaken at the commencement of the year, with the remainder received or spent at the end of the year;
- the return on assets component of the revenue benchmark is received at the end of the year; and
- the timing of the share of revenue in respect of operating and maintenance expenditure is aligned with the timing of these costs.

It noted that, intuitively, these assumptions would be weighted towards the interests of the distributors. The third of the above assumptions is likely to be biased against the distributors (and imply a working capital requirement). However, the second of the above assumptions is likely to favour the distributors because revenue is actually received progressively over each year. The 'return on assets' share of revenue accounts for about half of the revenue stream, and the error in the implicit timing assumption would be approximately six months. Therefore, the latter positive bias would be expected to more than offset the negative bias from omitting a working capital allowance. The Commission noted that Multinet had examined the within-year timing of its cash flows, which suggested that there was no material bias in either direction. As discussed earlier, the Commission's analysis of the timing of the cash flow for the Victorian electricity distributors suggests that this intuition is correct.

Accordingly, the Commission concluded that Envestra had not demonstrated that the 'simple target revenue formula' would imply a revenue stream that failed to compensate investors for the opportunity cost of their funds (that is, taking account of all revenue and all expenditures). The Commission adopted Multinet's analysis, and so did not adjust the 'simple target revenue formula' revenue benchmark either positively or negatively.

D.4 Responses to Draft Decision

In its response to the Draft Decision, Envestra presented a further detailed analysis of the Commission's application of the analytical framework for assessing the accuracy of the simple target revenue formula. In doing so, it supported the analytical approach discussed above, stating that:

> Envestra are broadly comfortable with the overall construct provided the execution is 'correct'.[824]

However, it also considered that the Commission had erroneously applied this analytical framework, and in particular that there was a factual error in the Commission's analysis that resulted in a bias against finding that an allowance for working capital is necessary.[825]

Notwithstanding its apparent acceptance of the Commission's proposed analytical framework, Envestra also argued that the implicit timing assumptions embedded in the simple target revenue formula differed from generally accepted practice in that:

824 Envestra, Working Capital and the Building Block Approach, 9 August 2002, p.8.
825 ibid, p.4.

> Practice and guidelines for capital expenditure analysis treat capital outlays as if they occur at the beginning of a period, typically a year with revenue and expenses occurring at the end of the period.[826]

It also expressed the view that the Total Revenue in the Draft Decision violates the Gas Code, in that it:

- does not provide a stream of revenue that recovers efficient costs (referring to section 8.1); and
- is not calculated in accordance with generally accepted industry practice (referring to section 8.4).[827]

Further, Envestra stated that:

> A universally accepted cost of doing business is in the provision of working capital. Envestra has demonstrated in its previous submission to the ESC that regulators throughout Australia have included working capital in the calculation of working capital. Consequently, the Access Code specifically requires the cost of working capital to be included in Total Revenue.[828]

It also stated that it is appropriate to adopt a conservative approach on this matter. In addition, Envestra reiterated its query as to the Commission's reasons for changing its approach from the 1998 decision.

In their submissions responding to the Draft Decision, the other distributors revised their earlier conclusions and adopted Envestra's analysis. For example, TXU noted that:

> Whilst TXU Networks believes that the general thrust of the approach taken by the Commission is acceptable, there is an issue with the way the Commissions' model calculates the annual revenue requirement in the weekly flow model. The nature of this issue was outlined in the Envestra submission to the Commission.[829]

Similarly, Multinet noted that:

> The company's position on this matter was formed using the working capital model provided by the Regulator. Further analysis of that model has indicated that there is a need for further detailed discussion between the Regulator and distributors in relation to this issue, before the Final Decision. Multinet would therefore welcome the opportunity of discussing this matter in further detail with the Regulator well in advance of the Regulator's Final Decision.[830]

---

826 ibid, p.19.

827 ibid, p.4.

828 ibid, p.5. Note that Envestra's summary of the stance of other regulators differed in its 'Conclusion' section, where it noted that 'a majority' of other Australian regulators have provided a working capital allowance (p.22).

829 TXU, Response to the Draft Decision, 7 August 2002, Attachment G, p.1.

830 Multinet, Response to the Draft Decision, 7 August 2002, p.76. Multinet also commented on the year-to-year fluctuation in expenditures in this section, which is relevant to the method that is used to determine expenditure forecasts rather than the analysis of within-year timing, and is addressed in sections 3.3 and 3.4.

In view of the complexity of the matter, TXU requested an opportunity to meet with the Commission to discuss the analysis further. In response, the Commission met with the distributors and their respective advisers on 22 August 2002. At that meeting, Envestra elaborated further on its analysis, and the Commission presented its initial views on that analysis. In particular, the Commission noted that it had analysed the issue correctly and that it considered that Envestra's analysis was flawed. Envestra submitted a further submission after that meeting, which referred to the Commission's further analysis (discussed further below). In addition to reiterating the comments summarised above, it noted that:

- the reference to industry practice in section 8.4 is a reference to 'the method that is used most commonly by investors and managers of corporations in calculating net present values and internal rates of return';[831] and
- investors in the gas businesses expected the formula used in 1998 to be used in this review. It stated that the Commission is required to consider 'previous investment decisions and the legitimate business interests', which 'means that, at a minimum, the 1998 Final Decision Total Revenue formula must be used in the Final Decision'.[832]

D.5 Further analysis

Broadly, the distributors' submissions to the Draft Decision (as well as Envestra's previous submissions) queried:

- whether the Commission's use of the 'net present value' rule to assess whether the simple target revenue formula (and, related to this, whether an allowance in respect of working capital is justified) is consistent with the requirements of the Gas Code; and
- assuming that the methodology is consistent with the requirements of the Gas Code, whether the Commission has applied correctly the 'net present value' rule.[833]

Application of the net present value rule

As noted above, Envestra argued that the Commission had erroneously applied its 'net present value' approach for assessing whether working capital is required although, it supported the Commission's proposed method of analysis.[834] It should be noted that Envestra's adviser, Dr Stephen Bishop, supported the Commission's view about the timing assumptions implied in its simple target revenue model. As discussed above, intuition suggests that these timing assumptions would be weighted towards the interests of the distributors.

---

831 Envestra, Summary Submission, September 2002, p.19.

832 ibid, p.20.

833 Note the caveat in footnote 808.

834 Dr Stephen Bishop also supported the Commission's approach to analysing working capital, but (as with Envestra) considered that the Commission had implemented this approach incorrectly.

The Commission’s approach essentially involved calculating the *precise* revenue benchmark given assumptions about the timing of revenue receipts and expenditure within that year – which is the revenue stream that generates cash flow with a net present value of zero over a year.[835] Comparing this precise revenue benchmark to the revenue benchmark generated by a simple target revenue model suggests that the simple target revenue formula accurately accounts for the true timing of cash flow over a year.

If the *precise* revenue benchmark exceeded the *simple* revenue benchmark, then the Commission would be likely to conclude that the use of the simple formula created a bias against the distributors, and that there would need to be an adjustment (either through an additional allowance, or by adopting a different simple target revenue formula). If the precise revenue benchmark was lower than that implied by the simple target revenue formula, then the Commission would be likely to conclude that the simple formula favoured the distributors, and as a result no additional allowance would be justified.[836] The Commission has previously expressed the difference in the two revenue streams as a percentage of the simple revenue benchmark – which Envestra has referred to as the ‘under/over index’.

Mathematically, the precise revenue benchmark is calculated, first, by finding the stream of revenue, R_i that solves:

$$-RAB_{Open} + \sum_{i=1}^{365+} \frac{R_i - O\&M_i - Capex_i}{(1+r)^{i/365}} + \frac{RAB_{Close}}{(1+r)} = 0$$

where $O\&M_i$ is the operating and maintenance expenditure on day i, $Capex_i$ is the capital expenditure on day i, RAB_{Open} and RAB_{Close} are the regulatory asset values at the start and finish of the year, and r is the (effective annual) discount rate.[837]

Daily expenditures are derived by making simple (but realistic) assumptions about the timing – such as that the rate of expenditure is constant throughout the year, the distributor is invoiced monthly in arrears, and is given two weeks to pay. Assumptions about the timing of revenue are easier – the practice in Victoria is for gas meters to be read bi-monthly, and for the distributors to bill the retailers twice monthly. Once the stream of revenue (R_i above) is derived, the Commission calculates the precise target revenue as the simple sum of the revenue receipts, that is:

$$\textit{Precise}\text{ Revenue Benchmark} = \sum_{i=1}^{365+} R_i$$

Envestra (and its expert adviser) agreed with the method explained above, except for the last step (that is the conversion of the stream of revenue, R_i into the precise revenue benchmark). It argued that it is incorrect to use a simple sum in this analysis, and that a future value should be used instead.[838]

835 Note the caveat in footnote 808.

836 If the analysis were applied symmetrically, identifying a positive bias would imply a downward adjustment to the revenue benchmark.

837 The cash flow may be discounted over more than a year as some of the revenue and expenditure in respect of a year often falls over into the next year.

838 Envestra, Working Capital and the Building Block Approach, 9 August 2002, p.11.

As noted above, the Commission does not consider that it has made an error, as suggested by Envestra. At the meeting of 22 August 2002, the Commission noted that as the role of the regulator is to assess reference tariffs, the most appropriate indicator is the *price* that would result. Thus, the simple target revenue formula would be weighted towards the interests of distributors if the price that is derived using this formula is greater than the price required to provide cash flow with a net present value of zero over the year.[839] Further, it demonstrated that:[840]

- comparing the 'simple sum' of revenue with the revenue benchmark (as the Commission had done) is a proxy for the price that is implied by each approach. Thus, the Commission's 'under/over index' is an accurate indicator of the extent and direction of any bias in the revenue benchmark;
- Envestra's analytical framework generated a number of perverse results, for example, a distributor would be indifferent between receiving the year's revenue at the start of the year on the one hand, and at the end of the year, at the other. This is clearly incorrect – money received at the start of the year is more valuable than money received at the end.

Only Envestra responded to the Commission's analysis presented at the meeting:

> If prices were set more frequently, we acknowledge that the simple sum of the more frequently determined revenues would fall below this amount and below the amount determined using average capital as the basis for calculating the return on asset component of revenue ($105.0 million). However, since they are not set on this basis, we would expect that the present and future value of the annual and intra period revenue coincide. This will occur with annual revenue set at $106.7 million but will not if annual revenue is set as the simple sum of intra period revenues.[841]

The Commission notes that its analysis assumes that prices are fixed over a year (as is currently the case), and will continue over the next regulatory period. Accordingly, it does not consider that Envestra has demonstrated any flaws in the application of the 'net present value' approach.

Regarding the implications of applying this analysis, in the Draft Decision, the Commission adopted the conclusions of Multinet's analysis, namely that applying this formula would not result in a material bias. The Commission has not received any further arguments that this conclusion is incorrect.[842] Accordingly, it has again adopted the conclusions of Multinet's analysis in this Final Decision.

Gas Code requirements

As summarised above, Envestra presented a number of propositions about the requirements of the Gas Code. In particular, it argued that:

- the Commission's simple target revenue formula was not formulated 'in accordance with generally accepted industry practice', and it presented its own

839 Note the caveat in footnote 808.

840 The financial model used to demonstrate these results at the meeting was provided to the distributors.

841 Envestra, Summary Submission, 12 September 2002, p.20.

842 Rather, Envestra's analysis – if interpreted correctly – would suggest that any bias in the use of the simple target revenue formula is likely to favour the distributors.

interpretation of 'generally accepted industry practice'. This contention referred to section 8.4 of the Gas Code;[843]

- as (it argued) the Commission had erroneously applied the 'net present value' approach discussed above, the total revenue would not provide a stream of revenue that recovers efficient cost, as required by section 8.1(a) of the Gas Code;[844] and
- investors in the gas businesses expected that the formula used in 1998 would continue to be used in the future, and that as a result the Commission must consider:
  - previous investment decisions.[845] Whilst it did not specifically refer to any provisions of the Gas Code, the Commission has assumed that this is a reference to section 8.1(d) and that Envestra's point is that a change to the method of determining total revenue will 'distort investment decisions' in pipeline systems;[846]
  - legitimate business interests. Whilst it did not specifically refer to any provisions of the Gas Code nor to the precise form of the legitimate business interest, the Commission has assumed that this is a reference to section 2.24(a) of the Gas Code, and that the legitimate business interest implied is an interest in the regulator not changing its method of regulation in a manner that may be adverse to the distributors.[847]

Regarding the first of these matters, section 8.4 of the Gas Code provides that:

> The methodology used to calculate the Cost of Service, an IRR or NPV should be in accordance with generally accepted industry practice.
>
> However, the methodology used to calculate the Cost of Service, an IRR or NPV may also allow the Service Provider to retain some or all of the benefits arising from efficiency gains under an Incentive Mechanism. The amount of the benefit will be determined by the Relevant Regulator in the range of between 100% and 0% of the total efficiency gains achieved.

The Commission notes that, while Envestra has put forward what it contends to be 'generally accepted industry practice' related to the application of the IRR or NPV approaches, it has not advanced evidence on practice with respect to the Cost of Service approach. Accordingly, Envestra's evidence may not be relevant to the interpretation of section 8.4.

---

843 Envestra, Working Capital and the Building Block Approach, 9 August 2002, pp.4, 19; Envestra, Summary Submission, 12 September 2002, p.19-20.

844 ibid, p.4.

845 Under the target revenue formula applied in 1998, the 'return on assets' was calculated by applying the cost of capital to the opening asset value, plus half of the capital expenditure forecast to occur within that year.

846 Envestra, Summary Submission, 12 September 2002, p.20.

847 ibid.

However, as noted above, the NPV and IRR approaches are alternative means of aligning the present value of revenue and cost – in effect, mathematical transformations where the same inputs are used. The cost of service approach could be demonstrated to be merely a rearrangement of a present value calculation, and thus deliver the same results where there is a common set of assumptions. Accordingly, the Commission has also considered Envestra's evidence on industry practice to apply equally in relation to the IRR or NPV approach, and the Cost of Service approaches respectively.

In interpreting this provision, Envestra has argued that:

- the relevant industry practice is the 'method commonly used by investors and managers of corporations in calculating net present values and internal rates of return'; and
- in undertaking an NPV analysis, the standard practice of this industry is to assume that capital expenditure occurs before the start of each year, and that revenue and the remainder of expenditure occurs on the last day of each year.

In this Final Decision, the Commission has assumed that Envestra's comment about the relevant industry is correct. However, it is not persuaded that there is a 'generally accepted industry practice' in relation to the timing assumptions employed in undertaking NPV analyses that to the effect that capital expenditure in relation to each year should be assumed to have been undertaken prior to the start of each year.

The Commission accepts that it is common when assessing the feasibility of a new project to assume that an initial outlay of capital expenditure is required prior to the start of the discounting period. Such an assumption is also likely to provide a very close proxy for the actual timing of this expenditure.[848] However, in relation to *ongoing* capital expenditure, the Commission considers that, to the extent that there is a common practice, that practice is to assume that such expenditures occur at the end of each year.

Indeed, Envestra appears to have accepted:

> When capital expenditure is incurred in subsequent periods and a residual value is explicitly included, the more general form of the equations becomes:
>
> $$NPV = Initial\_Outlay_0 + \sum_{t=1}^{n} \frac{Revenue_t - Opex_t - Capex_t}{(1+r)^t} + \frac{Residual\_Value_n}{(1+r)^n}$$
>
> [849]

[848] Moreover, if it takes some years to install the relevant infrastructure or equipment, then the initial outlay may include an allowance for the time value of money (eg. interest during construction).

[849] Envestra, Working Capital and the Building Block Approach, 9 August 2002, p.19.

The Commission considers that, as the gas distributors are an ongoing operation, the forecasts of capital expenditure that are reflected in reference tariffs are properly interpreted as 'capital expenditure … incurred in subsequent periods'.[850] Envestra's proposed formula implies that capital expenditure is incurred at the end of each year, which is consistent with Envestra's assumption made in a submission on another matter,[851] and also consistent with the simplifying assumption that the Commission understands is often adopted in 'net present value' analysis. The Commission notes that the assumption that capital expenditure occurs at the end of each year would result in revenue benchmarks that are not materially different to those determined under the simple target revenue formula discussed above.

Notwithstanding the common simplifying assumption about the timing of cash flow discussed above, the Commission does not consider that the evidence provided by Envestra has established a 'generally accepted industry practice' with respect to the assumptions to be adopted for the timing of cash flow. The Commission considers it more likely that such common simplifying assumptions would be adopted, except to the extent that greater precision were considered to be appropriate, given the materiality of the assumption compared to the overall precision of the analysis being undertaken. The Commission notes that some popular practitioner texts advocate greater precision in the assumption about the timing of cash flow. For example, leading finance experts, Brealey and Myers, suggest that an assumption of continuous cash flows may be more appropriate:

> There is a particular value to continuous compounding in capital budgeting, where it may often be more reasonable to assume that a cash flow is spread evenly over a year than that it occurs at a year's end.[852]

Regarding section 8.1(a) of the Gas Code, Envestra appeared to accept that the appropriate means of assessing whether or not the particular target revenue formula is consistent with section 8.1(a) of the Code is to correctly apply the 'net present value' approach discussed above. The Commission accepts this view. As discussed above, the Commission considers that Envestra has incorrectly applied the 'net present value' approach, and that the correct application implied that the Commission's formula would generate a revenue stream that is not materially different to that required if the actual timing of revenue within each year were taken into account.

Accordingly, the Commission considers that its proposed formula for deriving Total Revenue is consistent with section 8.1(a). In contrast, Envestra's proposed formula would generate a materially higher level of revenue and is therefore not consistent with section 8.1(a).

---

850 The capital base (or regulatory asset base) at the start of a period can be interpreted as the initial outlay.

851 Envestra, Network Marketing Plan (Confidential), p.7. The capital expenditure that was assumed to occur at the end of each year related to the expenditure required to connect new customers.

852 Brealey, R and S Myers, *Principles of Corporate Finance*, (McGraw-Hill, 5ed,) 1996, p.44.

Regarding section 8.1(d), the Commission accepts that material changes to regulatory practice may distort investment in pipeline systems.[853] However, it notes that the simple target revenue formula proposed will merely bring incremental revenue from new projects closer to incremental cost (but not below incremental cost), and as a result it is not clear that it would significantly distort pipeline system investment.

The Commission notes that section 8.1(d) also requires that there is no distortion in upstream or downstream industries. The Commission considers that such distortions are likely to be minimised by aligning revenue closer to cost, which is achieved under the Commission's proposed target revenue formula. Envestra did not refer to the other objectives in section 8.1 in the context of the target revenue formula including section 8.1(e), which refers to 'efficiency in the level' of reference tariffs. The Commission considers that its approach is more likely to promote efficiency in the level of reference tariffs as its proposed target revenue formula will align revenue closer to cost.

The Commission has considered the other factors in sections 8.1 and 8.2. However, the submissions received by the Commission have not raised, and the Commission does not consider that these other factors explicitly warrant any analysis in addition to that already undertaken and set out above.

Envestra also referred to section 2.24(a) of the Gas Code. As noted above, these factors are relevant to reconciling and assigning weight to the implications of section 8.1 objectives. The Commission accepts Envestra's argument that stability in the regulatory approach is in the distributors' legitimate business interests, which would suggest continuing the formula used in 1998. However, it notes that Envestra has not referred to any other factors in section 2.24, which the Commission considers have the following implications:

- as the Commission's proposed formula will align revenue more closely with (but not below) cost, it is more consistent with the economically efficient operation of the pipelines (section 2.24(d));
- whilst a consistent regulatory approach from one period to the next would be one element of the public interest, improving the administration of regulation where justified would also promote the public interest (as discussed further below) (2.24(e)); and
- as the Commission's proposed formula is likely to result in lower transportation charges (but not so low as to dissuade new investment), this is likely to better promote competition in related markets (section 2.24(e)) and also promote the interests of users and prospective users (section 2.24(f)).

The Commission has considered the other factors in section 2.24. However, the submissions received by the Commission have not raised, and the Commission does not consider, that these other factors explicitly warrant any analysis in addition to that already undertaken and set out above.

853 Envestra did not propose that the formula adopted in 1998 continue to be applied. Rather, it proposed (in its submissions subsequent to the Draft Decision) that a formula that provides a materially higher amount for Total Revenue be applied (see, eg. Envestra, Summary Submission, 12 September 2002, p.20).

A further matter the Commission considers is relevant is that it did not address expressly the appropriateness of the target revenue formula adopted in its 1998 decision, and instead merely adopted the applicants' proposal. The Commission notes that its 1998 decision was the first decision on regulated charges that it had ever made, and was also one of the first decisions under the Gas Code. It considers it is generally consistent with the factors above for regulators to refine and improve their approaches over time, although in some circumstances it will be necessary to consider whether and how particular improvements or refinements can be made in light of those factors (in particular, the need to take account of the legitimate business interests to both service providers and users).[854]

Having regard to the objectives in section 8.1 and factors in section 2.24, the Commission considers that, on balance, its proposed target revenue formula is appropriate in light of the requirements of the Gas Code.

D.6 Final Decision

The Commission has adopted the following target revenue formula in this Final Decision (abstracting from company tax and inflation):

$$\text{Target Revenue}_i = \text{WACC x Average Asset Value}_i + \text{Depreciation}_i + \text{O\&M}_i$$

854 The Commission does not consider that refinement and improvement necessarily implies changes adverse to the distributors.

Appendix E Price control formula

Chapter 4 sets out the Commission's Final Decision with respect the distributors' proposed reference tariff policies. This appendix contains the detailed price control formulae that are discussed in chapter 4.

BOX E.1
PRICE CONTROL FORMULA – 2003 & 2006-07

$$(1+CPI_t)(1-X_t)(1+L_t) \geq \frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} \bullet q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} \bullet q_{t-2}^{ij}}, i = 1,...n; \ j = 1,...m$$

where the Distributor has n Reference Tariff categories, each category having up to m Reference Tariff components and where:

p_t^{ij} **is the proposed Reference Tariff for component j of Reference Tariff i in Calendar Year t;**

p_{t-1}^{ij} **is the Reference Tariff being charged for component j of Reference Tariff i in Calendar Year $t-1$;**

q_{t-2}^{ij} **is the quantity of component j of Reference Tariff i that was sold in Calendar Year $t-2$;**

CPI_t **is defined in the glossary;**

X_t **is the X factor applying to each of the Distributors; and**

L_t **is the Licence Fee factor as defined in Box E.4**

BOX E.2

PRICE CONTROL FORMULA – 2004

$$(1+CPI_{2004})(1-X_{2004})(1+L_{2004})(1+A) \geq \frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{2004}^{ij} \bullet q_{2002}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{2003}^{ij} \bullet q_{2002}^{ij}}, i = 1,...n; j = 1,...m$$

where the Distributor has n Reference Tariff categories, each category having up to m Reference Tariff components and where:

p_{2004}^{ij}	**is the proposed Reference Tariff for component j of Reference Tariff i in Calendar Year 2004;**
p_{2003}^{ij}	**is the Reference Tariff being charged for component j of Reference Tariff i in Calendar Year 2003;**
q_{2002}^{ij}	**is the quantity of component j of Reference Tariff i that was sold in Calendar Year 2002;**
CPI_{2004}	**is the CPI for Calendar Year 2004, as defined in the Glossary;**
X_{2004}	**is the X factor for Calendar Year 2004, applying to each of the Distributors;**
L_{2004}	**is the Licence Fee factor for Calendar Year 2004, as defined in Box E.4; and**
A	**is the adjustment factor A to account for the unrecovered correction factor in the first access arrangement period.**

BOX E.3

PRICE CONTROL FORMULA – 2005

$$\frac{(1+CPI_{2005})(1-X_{2005})(1+L_{2005})}{(1+A)} \geq \frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{2005}^{ij} \bullet q_{2003}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{2004}^{ij} \bullet q_{2003}^{ij}}, i = 1,...n; j = 1,...m$$

where the Distributor has n Reference Tariff categories, each category having up to m Reference Tariff components and where:

p_{2005}^{ij}	**is the proposed Reference Tariff for component j of Reference Tariff i in Calendar Year 2005;**
p_{2004}^{ij}	**is the Reference Tariff being charged for component j of Reference Tariff i in Calendar Year 2004;**
q_{2003}^{ij}	**is the quantity of component j of Reference Tariff i that was sold in Calendar Year 2003;**
CPI_{2005}	**is the CPI for Calendar Year 2005, as defined in the Glossary;**
X_{2005}	**is the X factor for Calendar Year 2005, applying to each of the Distributors;**
L_{2005}	**is the Licence Fee factor for Calendar Year 2005, as defined in Box E.4; and**
A	**is the adjustment factor A to account for the unrecovered correction factor in the first access arrangement period, as defined in Box E.5.**

BOX E.4
LICENCE FEE FACTOR

$$Lt = \frac{1 + \dfrac{lf_{t-1} \bullet (1+WACC)}{SR_t}}{1 + \dfrac{lf_{t-2} \bullet (1+WACC)}{SR_{t-1}}} - 1$$

where:

lf_{t-1} **is the Licence Fee paid by the Distributor for the Financial Year ending June** $t-1$**;**

lf_{t-2} **is the Licence Fee paid by the Distributor for the Financial Year ending June** $t-2$**;**

SR_t **is the smoothed revenue for Calendar Year** t**;**

SR_{t-1} **is the smoothed revenue for Calendar Year** $t-1$**;**

$WACC$ **is the pre tax WACC applying to each Distributor; and**

For the Calendar Year 2003, lf_{t-2} **is equal to zero.**

BOX E.5

ADJUSTMENT FACTOR A

$$A = \frac{F_{2004}}{SR_{2004}}$$

where:

F_{2004}	**is a correction factor, as calculated in Box E.6; and**
SR_{2004}	**is the smoothed revenue for Calendar Year 2004.**

BOX E.6

CORRECTION FACTOR F

$$F_{2004} = \left(Fa_{2004} + Fb_{2004}\right) \bullet \left(1 + WACC\right) \bullet \left(1 + CPI_{2004}\right)$$

where:

Fa_{2004}	**is a correction factor for Calendar Year 2002, as calculated in Box E.7;**
Fb_{2004}	**is a correction factor for Calendar Year 2001, as calculated in Box E.8;**
FDV_{2002}	**is the forecast quantity of gas distributed in Calendar Year 2002, calculated in accordance with Clause B.3.2 of the Tariff Order;**
$WACC$	**is the pre tax WACC applying to each Distributor; and**
CPI_{2004}	**is the CPI for Calendar Year 2004, as defined in the Glossary.**

BOX E.7

CORRECTION FACTOR Fa

$$Fa = \left[(ADV_{2002} \bullet MADT_{2002}) - ADR_{2002}\right] \bullet (1 + CPI_{2003})(1 + WACC) -$$
$$(MADT_{2002} - FADT_{2002}) \bullet FDV_{2002} \bullet (1 + CPI_{2002})(1 + CPI_{2003})$$

where:

ADV_{2002} **is the total quantity of gas distributed in Calendar Year 2002;**

$MADT_{2002}$ **is the maximum average distribution tariff in Calendar Year 2002, calculated in accordance with clause B.3.3 of the Tariff Order;**

ADR_{2002} **is the total amount of distribution revenue earned in Calendar Year 2002;**

CPI_{2003} **is the CPI for Calendar Year 2003, as defined in the Glossary;**

CPI_{2002} **is the CPI for Calendar Year 2002, as defined in the Glossary;**

$WACC$ **is the pre tax WACC applying to each Distributor;**

$FADT_{2002}$ **is the forecast average distribution tariff in Calendar Year 2002, calculated in accordance with clause B.3.2 of the Tariff Order; and**

FDV_{2002} **is the forecast quantity of gas distributed in Calendar Year 2002, calculated in accordance with Clause B.3.2 of the Tariff Order.**

BOX E.8
CORRECTION FACTOR Fb

$$Fb = [(ADV_{2001} - EDV_{2001}) \bullet MADT_{2001} - \left(ADR_{2001} - EDR_{2001}\right)] \bullet (1 + I_{2002})$$

where:

ADV_{2001} **is the total quantity of gas distributed in Calendar Year 2001;**

EDV_{2001} **is the estimated quantity of gas distributed in Calendar Year 2001, calculated in accordance with Clause B.3.5 of the Tariff Order.**

$MADT_{2001}$ **is the maximum average distribution tariff in Calendar Year 2001, calculated in accordance with clause B.3.3 of the Tariff Order;**

ADR_{2001} **is the total amount of distribution revenue earned in Calendar Year 2001;**

EDR_{2001} **is the estimated amount of distribution revenue earned in Calendar Year 2001, calculated in accordance with Clause B.3.5 of the Tariff Order; and**

I_{2002} **is the interest rate for Calendar Year 2002, as calculated in accordance with clause B.3.5 of the Tariff Order.**

BOX E.9

REBALANCING CONTROL FORMULA – 2003

$$P_{2003}^{ij} \leq P_{2002}^{ij} \bullet (1 + CPI_{2003} - 0.01)$$

where:

p_{2003}^{ij}	**is the proposed Reference Tariff for component j of Reference Tariff in Calendar Year 2003;**
p_{2002}^{ij}	**is the Reference Tariff being charged for component j of Reference Tariff i in Calendar Year 2002; and**
CPI_{2003}	**is the CPI for Calendar Year 2003, as defined in the Glossary.**

BOX E.10

REBALANCING CONTROL FORMULA – 2004-07

$$(1+CPI_t)(1+Y_t)(1+L_t) \geq \frac{\sum_{j=1}^{m} p_{2004}^{j} \bullet q_{2002}^{j}}{\sum_{j=1}^{m} p_{2003}^{j} \bullet q_{2002}^{j}}, j = 1,...m$$

where:

p_{2004}^{j} **is the proposed Reference Tariff for component j of Reference Tariff i in Calendar Year 2004;**

p_{2003}^{j} **is the Reference Tariff being charged for component j of Reference Tariff i in Calendar Year 2003;**

q_{2002}^{j} **is the quantity of component j of Reference Tariff i that was sold in Calendar Year 2002;**

CPI_t **is defined in the glossary;**

Y_t **is the rebalancing constraint applying to each of the Distributors; and**

L_t **is the Licence Fee factor as defined in BOX E.4.**

If Lt <0, then $(1+L_t)$=1.

If in Calendar Year 2004:

A **>0 then the rebalancing control formula is:**

$$(1+CPI_t)(1+Y_t)(1+L_t)(1+A) \geq \frac{\sum_{j=1}^{m} p_{2004}^{j} \bullet q_{2002}^{j}}{\sum_{j=1}^{m} p_{2003}^{j} \bullet q_{2002}^{j}}, j = 1,...m$$

where:

A **is the adjustment factor A to account for the unrecovered correction factor in the first access arrangement period, as defined in Box E.5.**

Otherwise the rebalancing control formula is unchanged.

If in Calendar Year 2005:

A **<0 then the rebalancing control formula is:**

$$\frac{(1+CPI_t)(1+Y_t)(1+L_t)}{(1+A)} \geq \frac{\sum_{j=1}^{m} p_{2004}^{j} \bullet q_{2002}^{j}}{\sum_{j=1}^{m} p_{2003}^{j} \bullet q_{2002}^{j}}, j = 1,...m$$

Otherwise the rebalancing control formula is unchanged.

Box E.11

ANCILLARY REFERENCE SERVICES

$$ART_t = ART_{t-1} \bullet (1 + CPI_t)$$

where:

ART_t	**is the Ancillary Reference Tariff that applies in Calendar Year** t
ART_{t-1}	**is the Ancillary Reference Tariff that applies in Calendar Year** $t-1$**; and**
CPI_t	**is defined in the Glossary.**