Envestra

Investing in energy infrastructure

Victorian

Access Arrangement Information

30 March 2012

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Part A – Background

1. Introduction

1.1 Purpose of this Document

Envestra Limited (ACN 078 551 685) is a publicly listed company that owns natural gas distribution networks across Australia. Envestra owns around 23,000 kilometres of natural gas distribution networks serving over 1,100,000 customers in Victoria, South Australia, Queensland, New South Wales and the Northern Territory. Envestra's current Access Arrangement period for Victoria ends on 31 December 2012.

Section 7 of the *National Gas (Victoria) Act 2008* (the Act) applies the National Gas Law (NGL), which is set out in the Schedule to the Act, as a law of Victoria. Section 26 of the NGL gives the National Gas Rules (NGR) the force of law in Victoria. Part 9 of the NGR makes the Australian Energy Regulator (AER) responsible for making a decision in relation to a revised Access Arrangement proposal submitted by Envestra.

Rule 52 of the NGR requires that Envestra submit by 30 March 2012 a revised Access Arrangement proposal for the period from 1 January 2013 to 31 December 2017. Rule 43 requires Envestra, when submitting a revised Access Arrangement proposal, to submit an Access Arrangement Information (AAI) for the Access Arrangement. Rule 42 states that an AAI is to contain information that is reasonably necessary for users and prospective users to:

- understand the background to the Access Arrangement or the Access Arrangement proposal; and
- understand the basis and derivation of the various elements of the Access Arrangement or the Access Arrangement proposal.

Envestra Limited submits this AAI to the AER for its Victorian network (the "Network") on behalf of its subsidiary Vic Gas Distribution Pty Ltd (ACN 085 899 001), which is the licensed distributor in respect of the Network.

1.2 The Victorian Network

The Network includes the distribution mains, inlets, meters, regulators and ancillary equipment that are used to provide pipeline services in that state. The Network serves the northern, outer eastern and southern areas of Melbourne, Mornington Peninsula, rural communities in northern, eastern and north-eastern Victoria and south-eastern rural townships in Gippsland.[1]

The Network comprises around 9,900 kilometres of mains delivering gas to around 575,000 customers. The Network has been constructed over a period of more than 100 years and consequently consists of a variety of pipe materials. The predominant pipe material used for gas mains up until the 1970s was cast iron and unprotected steel. Subsequent to this, polyethylene (PE) has been used as the predominant pipe material.

The type of pipe material dictates the maximum allowable operating pressure of the constituent parts of the Network. Since cast iron can only be operated at relatively low pressures compared to PE, the continual replacement of cast iron pipe with PE pipe means that the capacity of the Network is improving over time in many areas. Table 1.1 sets out the composition of the Network by pipe material.

1 The Network is divided into the following four zones; North, Central, Murray Valley and Bairnsdale. Maps outlining the zones covered by the Network are available from Envestra's website, which is found at: www.envestra.com.au.

Table 1.1: Network Composition by Pipe Material, 30 June 2011

	Cast Iron / Steel	PE	Protected Steel	PVC	Other	Total
Length (km)	695	5620	3064	538	0.3	9917

Table 1.2 shows the pressure tiers at which the Network operates. The transmission mains form the backbone of the Network and generally transport gas to urban areas, where lower pressure tiers are then used to deliver gas to customers. Where possible, high pressure pipes are used as this provides the highest capacity of gas per unit of length, and therefore provides the best ability to service customers during periods of peak demand.

Table 1.2: Network Pressure Tiers

Pressure Tier	Pressure Range (kPa)
Transmission	1,050 to 10,000
High Pressure HP2	515 to 1,050
High Pressure HP1	140 to 515
Medium Pressure	7 to 140
Low Pressure	1.4 to 7

1.3 Relevant Regulatory Regime

Section 27 of the NGL prescribes the functions and powers of the AER, which includes economic regulatory functions. Section 28 of the NGL provides that the AER must, in performing or exercising an economic regulatory function or power, perform or exercise that function or power in a manner that will or is likely to contribute to the achievement of the National Gas Objective (NGO), which is set out in section 23 of the NGL. The NGO states:

> *"The objective of this Law is to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas."*

Section 28 also provides that the AER must take into account the revenue and pricing principles when exercising discretion in approving or making a decision in respect of an Access Arrangement proposal. Section 24 of the NGL sets out the revenue and pricing principles, which are as follows:

- under subsection 24(2), a service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in providing reference services and complying with a regulatory obligation or requirement or making a regulatory payment;
- under subsection 24(3), a service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides, including:
  - efficient investment in, or in connection with, a pipeline with which the service provider provides reference services;

- the efficient provision of pipeline services; and

- the efficient use of the pipeline.

- under subsection 24(5), a reference tariff should allow for a return commensurate with the regulatory and commercial risks involved in providing the reference service to which that tariff relates;

- under subsection 24(6), regard should be had to the economic costs and risks of the potential for under and over investment by a service provider in a pipeline with which the service provider provides pipeline services; and

- under subsection 24(7), regard should be had to the economic costs and risks of the potential for under and over utilisation of a pipeline with which a service provider provides pipeline services.

This AAI demonstrates and explains how Envestra's revised Access Arrangement proposal satisfies both the NGO and the revenue and pricing principles.

The exercise of the AER's discretion in its decision making process regarding an Access Arrangement proposal, including in deciding whether Envestra has satisfied the NGO and the revenue and pricing principles, is governed by rule 40 of the NGR, which relevantly provides that:

- under subrule 40(1), if the NGL states that the AER has no discretion under a particular provision of the NGL, then the AER's discretion is entirely excluded in regard to an element of an Access Arrangement proposal that is governed by the relevant provision;

- under subrule 2, if the NGL states that the AER's discretion under a particular provision of the NGL is limited, then the AER may not withhold its approval to an element of an Access Arrangement proposal that is governed by the relevant provision if the AER is satisfied that it:
  - complies with the applicable requirements of the NGL; and
  - is consistent with applicable criteria (if any) prescribed by the NGL.

- under subrule 40(3), in all other cases the AER has full discretion to withhold its approval to an element of an Access Arrangement proposal if, in the AER's opinion, a preferable alternative exists that:
  - complies with the applicable requirements of the NGL; and
  - is consistent with applicable criteria (if any) prescribed by the NGL.

1.4 Requirements of an Access Arrangement Information

Rule 72 of the NGR states that an AAI in respect of an Access Arrangement proposal must include:

- capital expenditure (by asset class), operating expenditure (by category) and usage of the pipeline over the previous Access Arrangement period;

- the derivation of the change in the capital base over the previous Access Arrangement period;

- the projected capital base over the Access Arrangement period, including a forecast of conforming capital expenditure and depreciation and the basis for the forecast;
- to the extent it is practicable, a forecast of pipeline capacity and utilisation of pipeline capacity over the Access Arrangement period and the basis for the forecast;
- a forecast of operating expenditure over the Access Arrangement period and the basis for the forecast;
- the key performance indicators to be used to support expenditure to be incurred over the Access Arrangement period;
- the proposed rate of return, the assumptions on which the rate of return is calculated and a demonstration of how it is calculated;
- the proposed method for dealing with taxation, and a demonstration of how the allowance for taxation is calculated;
- a demonstration of how an allowance is to be made for any increments or decrements made under any incentive mechanism that applied in the previous Access Arrangement period;
- the proposed approach to the setting of reference tariffs, including the method used to allocate costs and a demonstration of the relationship between costs and tariffs;
- the rationale for any proposed reference tariff variation mechanism;
- the rationale for any proposed incentive mechanism;
- the total revenue to be derived from pipeline services for each regulatory year of the Access Arrangement period.

Related to the above, the AER has issued a Regulatory Information Notice (RIN) to Envestra that specifies the information that it requires for its decision making process. This information requirement must be consistent with the requirements of rule 72 as set out above. Attachment 1-1 of this AAI explains where in Envestra's proposal the information required by the RIN can be found. All information required by the RIN and the NGR has been provided by Envestra in this AAI. Attachment 1-2 is a completed template containing specific information requested by the AER.

1.5 Verification of Forecast Information

Rule 74 of the NGR requires that a forecast or estimate used in an Access Arrangement proposal must:

- be arrived at on a reasonable basis; and
- represent the best forecast or estimate possible in the circumstances.

The forecasts and estimates used in this AAI satisfy the above criteria. This reflects the rigorous process followed by Envestra to develop its forecasts, which process is summarised as follows:

- forecasts are based on the considerable expertise of Envestra and its contractor, APA Asset Management;

- forecasts for projects have been based on robust business plans that have been subject to thorough review as to their compliance with the relevant obligations of the NGL and NGR;
- where possible, forecasts have been based on the most recent actual information available, which information reflects revealed efficient expenditure/outcomes;
- all relevant drivers of a particular forecast have been taken into account and explained in this AAI, including by providing any data used to derive a particular forecast;
- reliance has been made on independent and expert advice in the preparation of forecast information, which advice has been attached to this AAI;
- adherence to strict business processes in developing and approving forecasts has been followed, including final approval of forecast information by Envestra's Board; and
- relevant industry stakeholders have been consulted, where appropriate, in deriving a forecast.

With regard to the last point, Envestra has liaised closely with Energy Safe Victoria to ensure that expenditure plans in respect of the forecast mains replacement program are consistent with the long term safety, reliability and security of the network.

1.6 Interpretation

Terms used in this AAI have the same meaning as they have in the Access Arrangement (see clause 2 of the Access Arrangement).

In this AAI:

- monetary values are expressed in 2011 dollar terms, unless indicated otherwise;
- certain numerical values may not precisely equate due to rounding;
- a reference to opex is a reference to operating expenditure, and a reference to capex is a reference to capital expenditure
- a reference to a "rule" is a reference to a National Gas Rule.

In this AAI, unless the context otherwise requires, where a word or meaning is capitalised it has:

- the meaning given to that word or phrase in the National Gas Rules; or
- the meaning given to that word or phrase in the glossary contained in the Access Arrangement.

1.7 Structure of the Access Arrangement Information

This AAI is structured as follows:

- Part A - Chapters 1 to 4 provide background information on the relevant regulatory framework, an overview of Envestra's operations, services and key business drivers and our past performance over the 2008 to 2012 Access Arrangement period;

- Part B - Chapters 5 to 12 cover the key components (or building blocks) that are used to derive total revenue for each year of the Access Arrangement period, including the return on capital, depreciation, operating expenditure, taxation and the outcomes of the incentive mechanism that applied in the previous Access Arrangement period; and

- Part C - Chapters 13 to 16 cover factors relevant to the derivation of reference tariffs, including demand forecasts, the tariff variation mechanism and non-tariff components of the Access Arrangement proposal.

1.8 Contact Details

The contact person for further details in relation to this AAI and the Access Arrangement to which it relates is:

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Group Manager - Commercial
Envestra Limited
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2. Business Overview

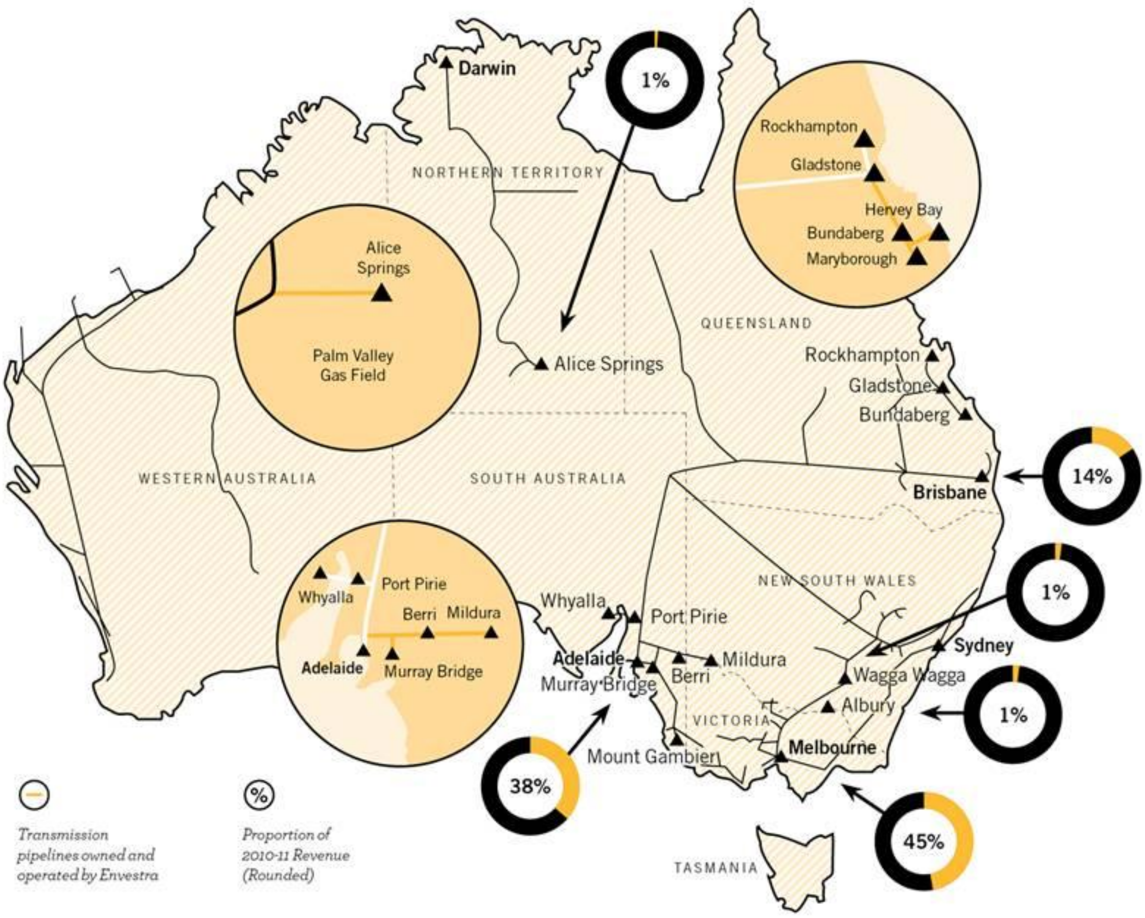
2.1 Introduction

Envestra is the leading gas distribution company in Australia, serving over 1,100,000 domestic and industrial/commercial customers. The Company owns around 23,000 kilometres of natural gas distribution networks and 1,100 kilometres of transmission pipelines in South Australia, Victoria, Queensland, New South Wales and the Northern Territory. Envestra's operating areas are shown in Figure 2.1.

Envestra is a publicly listed company on the Australian Stock Exchange (ASX) with over 18,000 shareholders as at 30 June 2011. The largest shareholder is the APA Group who holds 33% of the total shares in Envestra. The CKI Group holds 20% of total shares with the remainder split between institutional investors (22%) and retail investors (25%). Envestra had an enterprise value of $3.2 billion as at 30 June 2011.

As shown in Figure 2.1, the majority of Envestra's networks are located in Victoria and South Australia, with the former accounting for 45% of Envestra's total revenue in 2010/11. The domestic customer segment accounts for around 70% of total revenue and 96% of total customer numbers.

Figure 2.1: Envestra's Operating Territory



2.2 About Envestra

The history of Envestra can be broken down into the following five key stages:

- *Formation (1997)* – the period when Envestra was formed as a business focussed on gas distribution networks;
- *Establishment (1997 to 2002)* – the early years of the business where key business plans and processes were developed;
- *Contestability (2002 to 2005)* – the period when Government's introduced gas retail competition, which transformed the way the business operates as a result of the significant investments in IT infrastructure made during this time;
- *Consolidation (2005 to 2007)* – the period whereby Envestra positioned the business to successfully deliver on the long term interests of its stakeholders; and
- *Global Financial Instability (2007 to ongoing)* – the period of global financial market turmoil, which resulted in significant increases in the cost of capital.

2.2.1 Formation of Envestra (1997)

Envestra was formed as a specialised natural gas distribution company in September 1997 when it acquired the Boral Group's natural gas distribution networks in South Australia, Queensland and the Northern Territory.[2] Envestra was the first publicly listed company to be established focusing on owning energy network infrastructure. Other companies that owned network assets at this time tended to be large and vertically integrated with retail and/or generation activities.

Envestra was established as a dedicated asset owner with the operations outsourced to Boral Energy Asset Management (BEAM), a subsidiary of the Boral Group. The key motivation for this structure was to ensure that Envestra would continue to be a low cost operator following its split from the Boral Group through accessing the economies of scale, scope and know-how of a significantly larger organisation.[3]

The outsourcing structure was therefore a fundamental part of Envestra's business strategy when it was formed. This structure was considered by the Board to be the most effective way in which to create a viable, cost efficient new business that could:

- satisfy the requirements of the pending national regulatory framework;
- achieve cost outcomes at or better than that achieved by the often much larger and more diverse energy industry peers; and
- successfully acquire assets in the deregulated energy market, which did occur with the purchase of the Victorian business in 1999 and the Wagga Wagga business in 2010.

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2 The Boral Group had purchased the Brisbane Gas Company in 1971 and later purchased the South Australian Gas Company in 1993.

3 In 1998, Envestra reported an operating revenue of $117.4m compared to Boral's revenue of $4.7b, demonstrating the potential for scale economies from this arrangement (see Envestra and Boral Annual Reports, 1998)

2.2.2 The Establishment Phase (1997 to 2002)

Following its formation, the Envestra Board developed and implemented its own business plans to deliver on its objectives, which included:

- increasing its national footprint through the acquisition of the Palm Valley pipeline in 1998 and the Stratus network from the Victorian Government in 1999;
- increasing organic growth through a more targeted network development strategy than had existed previously;
- improving the integrity of the network by commencing a significant mains replacement program (around half of the networks acquired from the Boral Group were comprised of cast iron or unprotected steel);
- implementing long term and diversified financing arrangements;
- enhancing managerial skills by employing additional regulatory, financial and asset management resources; and
- rationalising regulatory arrangements through successful applications made to the National Competition Council to have a number of its smaller networks "uncovered".

The above actions were vital in positioning Envestra as a large, sustainable and efficient owner of natural gas distribution assets.

During this period, Boral divested its energy assets to create an independent company called Origin Energy. Origin Energy was established as a business focussed on the competitive retail and generation parts of the energy sector (as opposed to Envestra who was established to focus on the non-competitive parts). Network operations were transferred from BEAM to Origin Energy Asset Management (OEAM), which was part of a specialised energy company rather than part of a diversified industrial corporate.

2.2.3 Retail Contestability (2002 to 2005)

Consistent with the Government's energy reform agenda, gas retail markets were progressively opened to competition throughout the 2002 to 2005 period.

The introduction of full retail contestability (FRC) had significant implications for network businesses across Australia. This primarily reflected the new role given to distributors in providing meter reading and associated data management services (including facilitating customer transfers between retailers). This required Envestra to invest over $100 million to update its IT systems.

The new IT systems included asset management, billing and geographic information systems. These new systems not only allowed Envestra to perform its obligations under the retail market rules, but to also improve service levels to customers. For example, the increased automation of the business assisted Envestra in improving network control and management, metering and billing accuracy, leak management and repairs and to reduce transaction costs.

2.2.4 Consolidation (2005 to 2007)

With FRC systems bedded down, Envestra's attention moved to consolidating the business. Detailed business plans were developed through the Access Arrangement reviews in South Australia and Queensland in 2006 and Victoria and New South Wales in 2007 to increase network growth, replace aging assets and more generally to improve network performance. This included:

- upgrading asset management planning to guide investment decision making across the business;
- improving network performance and safety through the continuation of the mains replacement program;
- identifying opportunities to grow the network and expand the availability of natural gas supply;
- developing network development strategies to increase natural gas connections and usage; and
- working with governments to optimise the opportunity for natural gas to contribute to economic development and improved environmental outcomes.

In 2007 Origin Energy divested its networks business, including OEAM, to the APA Group (APA). Envestra negotiated a new outsourcing agreement governing how the APA Group would operate Envestra's networks. The APA Group is Australia's largest natural gas infrastructure group, owning and/or operating in excess of $8 billion in assets.[4] This allowed Envestra to continue to achieve efficient costs by accessing the considerable expertise and scale of the APA Group.

2.2.5 Global Financial Instability (2007 to ongoing)

There has been considerable turmoil in global financial markets since mid 2007. This instability was initially triggered in the economies of northern America and the United Kingdom. More recently, financial instability in European economies has continued to affect financial markets across the world.

2.2.5.1 Global Financial Crises (2007 to 2009)

The crisis in northern America and the United Kingdom was triggered by the collapse of prices in the housing market and the related high default rates on sub-prime mortgages. The deterioration in financial markets and loss of investor confidence resulted in the bankruptcy of Lehman Brothers on 15 September 2008. This date is commonly acknowledged as the beginning of the global financial crisis (GFC).

The GFC is commonly considered to be the worst financial crisis since the Great Depression of the 1930s. The GFC resulted in the dislocation of credit markets, collapse of financial institutions, the government bailout of banks and downturns in stock markets around the world. This led to reductions in consumer wealth, declines in credit availability and significant downturns in economic activity, which in turn led to a severe economic recession in many economies.

Governments, particularly in the United States and United Kingdom, were forced to support financial institutions and large corporations and loosen monetary policy to prevent further on-going economic instability. This caused government debt levels to increase significantly. In August 2011, Standard & Poor's (S&P) downgraded the credit rating of the United States Government in response to concerns over its substantial budget deficit and rising debt burden, which heightened concerns over the potential for sovereign default risk in that country.

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4 Envestra's total assets as at 30 June 2011 was $2.9 billion.

While the GFC is commonly thought to have passed, financial markets have not returned to the levels that existed prior to the onset of the GFC in mid-2007. Furthermore, the United States and United Kingdom economies remain depressed, driven by historically high debt levels, which has led to flow on impacts for other economies. This has resulted in investor risk aversion remaining elevated, as evidenced (for example) by the volatility in global stock markets.

2.2.5.2 European Crisis (2009 to ongoing)

The interconnectedness of global capital markets means that the financial stress and recessions experienced in the United States and the United Kingdom from 2007 put pressure on the financial systems of other economies (referred to as financial contagion). This has led to the European sovereign debt crisis, where governments with large debt levels and substantial budget deficits faced sharp rises in interest rates, which in turn made it difficult for them to service existing debt.

The European debt crisis was most strongly felt in Greece, Ireland, Spain and Portugal. The sovereign debt defaults have reduced the capital adequacy levels of many European banks, which has reduced their ability to lend. The debt crisis has also led to certain Eurozone countries introducing austerity measures aimed at reducing public debt levels. This in-turn has led to further weakening in both private and public sector spending. While most strongly felt in only a few Eurozone countries, it has become a perceived problem for the region as a whole.

On 5 December 2011, S&P placed its long-term sovereign rating on 15 members of the Eurozone on credit watch with negative implications, stating that this was due to:

> *"systemic stresses from five interrelated factors: 1) Tightening credit conditions across the eurozone; 2) Markedly higher risk premiums on a growing number of eurozone sovereigns including some that are currently rated 'AAA'; 3) Continuing disagreements among European policy makers on how to tackle the immediate market confidence crisis and, longer term, how to ensure greater economic, financial, and fiscal convergence among eurozone members; 4) High levels of government and household indebtedness across a large area of the eurozone; and 5) The rising risk of economic recession in the eurozone as a whole in 2012."*[5]

In August 2011, Glenn Stevens in commenting on the ongoing uncertainty in global markets noted that:

> *"People will understandably want to draw comparisons with the [northern American and United Kingdom] financial crisis of 2008. We cannot know, of course, what will transpire in the months ahead, but I think that what we have witnessed is best seen not so much as a new crisis, as part of the long aftermath of the 2008 crisis. Among countries at the heart of that crisis it was to be expected that, after serious problems in private-sector balance sheets, economic recovery would be a drawn out affair."*[6]

These global developments have had the effect of increasing the cost of funds for Australian banks, which has flowed through to the broader economy. Like the crisis in northern America and the United Kingdom, the European debt crisis is expected to result in a prolonged economic recession in the region, as noted by the Reserve Bank of Australia in its February 2012 Statement on Monetary Policy:

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5 Standard & Poor's 2011, 'Standard & Poor's Puts Ratings on Eurozone Sovereigns on CreditWatch with Negative Implications, 5 December 2011.

6 Glenn Stevens 2011, Opening Statement to the House of Representatives Standing Committee on Economics, 26 August 2011.

"Sovereign debt problems in a number of advanced economies continue to be a major factor influencing developments in the global economy. The economic data in Europe have deteriorated significantly since mid 2011 and a feedback loop between sovereign debt problems and deteriorating economic conditions has developed in some countries. The problems in Europe are having spillover effects to the rest of the world through trade, financial channels and an increase in broader economic uncertainty. Growth in Asia has slowed, although the region continues to expand at a faster pace than many other parts of the world. In the United States, economic indicators have picked up in recent months following a soft patch in mid 2011, although the fiscal position there also poses medium-term challenges. In line with these developments, the International Monetary Fund's (IMF) January World Economic Outlook Update made downward revisions to the forecasts in the September 2011 Outlook........ A further intensification of sovereign debt problems in Europe is still seen as the biggest risk to global growth."[7]

The clear message from the Reserve Bank of Australia is that market instability caused by the prospect of sovereign debt defaults and a constrained banking system in Europe will continue to have a negative impact on global economic growth, investor risk appetite and the cost of capital for some time to come.

In Australia, the government has maintained its 'AAA' credit rating due to relatively modest government debt levels. In a world where the number of 'AAA' rated corporate and sovereign entities is declining, Australian government bonds have been seen as a more attractive 'safe haven' asset. Consequently, as global uncertainty has increased so has the demand for Australian government bonds, which has resulted in a fall in bond yields to historically low levels.

One of the outcomes of global instability has therefore been to create a clear disconnect between investor return requirements (which are elevated) and government bond yields (which are depressed).

2.2.5.3 Implications for Envestra

The GFC along with the European debt crisis has had significant consequences on Envestra. As shown in figure 2.2, Envestra's share price fell from $1.15 on 1 July 2007 to a low of $0.29 on 26 February 2009 (the share price has since partially recovered to be at $0.69 as at 30 June 2011).

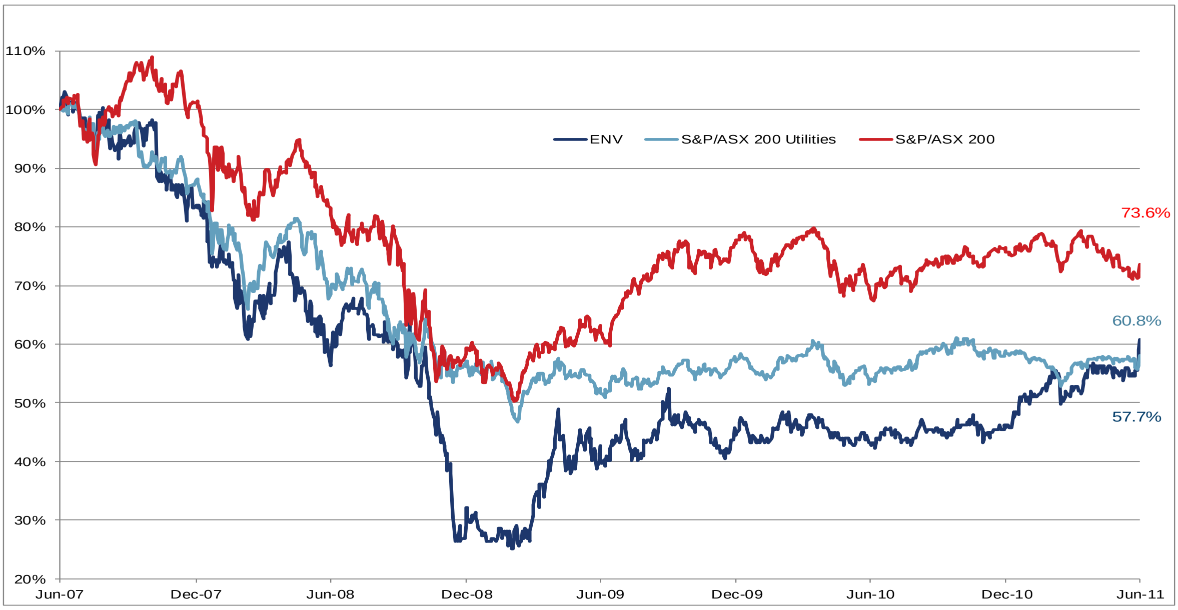
Following the unfavourable regulatory decision for the South Australian network in 2006, S&P chose to reduce Envestra's credit rating one notch from 'BBB' to 'BBB-' with a "stable" outlook:

"Envestra's tight capital structure means the company cannot maintain the 'BBB' rating in the face of a regulatory decision by ESCOSA that is harsher than the company's expectations. Envestra's cash flows will weaken in the medium term, going against Standard & Poor's expectations of a gradually and consistently improving trend.[8]

[7] Reserve Bank of Australia, *Statement on Monetary Policy*, February 2012.

[8] Standard & Poor's 2006, "*Research Update: Ratings on Envestra and EnVic Lowered to 'BBB-/A-3' Following ESCOSA Decision*, 31 July 2006.

Figure 2.2: Envestra's Share Price Movement



'BBB-' is the lowest investment grade credit rating available from S&P. The task of raising debt with a 'BBB-' credit rating is difficult and costly as risk appetite falls exponentially as credit quality declines. Indeed, some debt investors are not able or willing to lend to entities with a 'BBB-' credit rating.

The GFC dramatically increased investors' aversion to risk and restricted the availability of debt and equity capital to 1 in 100 year levels that were not anticipated at the time business plans and Access Arrangements were approved. This limited Envestra's ability to refinance debt and raise new capital to fund investment. Where capital was made available, it was at a significant premium to that allowed for in existing Access Arrangements, all of which were finalised before the onset of the GFC.

As S&P understood the gravity of events in the capital markets during 2008 it took the step of placing Envestra's 'BBB-' credit rating on a "negative" outlook.[9] A "negative" outlook attached to a 'BBB-' credit rating indicates the potential for a downgrade to non-investment level. The rating 'outlook' indicates the potential direction of a rating over the intermediate term, typically six months to two years, with consideration to changes in the economic and/or fundamental business conditions.

S&P noted that the major factor in its decision for the downgrade was Envestra's exposure to capital markets and its inability to raise debt and equity finance in an efficient manner:

> *"Envestra's highly leveraged capital structure, in conjunction with EnVic's underperformance, means the group is increasingly exposed to capital market sentiment at a time when conditions are particularly challenging."*[10]

Envestra responded to these financial pressures by deferring expenditure where this would not unreasonably compromise safety and service performance. Total capital expenditure was around 40% below benchmark levels over the 2008 to 2010 period, which was largely driven by a 70% reduction in mains replacement expenditure. There were also significant reductions in augmentation, IT and marketing expenditure over this period.

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9 Standard & Poor's 2008, "*Ratings Direct, Envestra Ltd*", 18 August 2008.
10 Standard & Poor's 2008, "*Ratings Direct, Envestra Ltd*", 18 August 2008.

These actions were necessary and prudent given the capital market environment, and accorded with S&P's expectations of how management should respond in such circumstances:

> *"...any environment where Envestra couldn't earn an adequate return on its capital may lead to reductions in forecasted capital expenditure"*[11].

Envestra's credit rating was restored to "stable" in 2009 and access to capital improved in 2010. This allowed capital expenditure to be significantly increased in an attempt to meet Access Arrangement benchmarks.

In addition to temporarily cutting expenditure, Envestra also managed the impact of the GFC by:

- rearranging financing arrangements to reflect the closure of bond markets, the departure of foreign banks from the domestic market and the capital limitations imposed by the major Australian banks;
- restructuring the balance sheet by raising equity and through consolidating financing arrangements; and
- implementing general business improvement initiatives through the budget process to improve efficiency.

As a result of these initiatives, Envestra is now better placed to grow and expand its natural gas networks into the future.

2.3 Envestra's Vision

Envestra's vision is to own and reliably operate natural gas networks, pipelines and related services that generate attractive returns to its shareholders (see figure 2.3). The objectives that guide Envestra in achieving its vision include:

- achieving a long term (pre-tax) return to shareholders (including distributions and capital gains) of at least 12.5%;
- operating networks safely and efficiently, complying with all laws and relevant industry standards, and enhancing their value by adding connections and augmenting capacity;
- promoting the use of natural gas as the most environmentally friendly fossil fuel and a cost competitive, convenient and readily available energy source for many consumers; and
- providing outstanding service to customers to ensure a continuing growth in customer connections to our networks and increasing gas deliveries each year.

Envestra is therefore focussed on facilitating improved economic and environmental outcomes through promoting efficient network growth and strong customer service (providing that rates of return on capital are sufficient to attract the required capital). Envestra's vision is consistent with the National Gas Objective (NGO), which states:

11 Standard & Poor's 2008, "*Ratings Direct, Envestra Ltd*", 18 August 2008.

> *"The objective of this Law is to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas."*

Central to Envestra achieving its vision (and the NGO) is its operating structure. Envestra, since its inception, has outsourced operations to a large and specialised contractor. This has provided Envestra with access to superior know-how and scale than would otherwise have been the case, which in-turn has delivered Envestra with cost outcomes that are consistent with good industry practice (see section 2.4).

With appropriate funding and marketing, Envestra is confident natural gas will continue to play an important role in achieving improved customer and environment outcomes.

Figure 2.3: Envestra's Vision and Objectives

Our vision is to own and reliably operate natural gas networks pipelines and related services that generate attractive returns to our shareholders.

THE FOLLOWING OBJECTIVES WILL ENABLE US TO DELIVER ON OUR VISION:

- Achieving a long term (pre-tax) annual return to our shareholders (including distributions and capital gains) of at least 12.5%
- Operating our networks safely and efficiently, complying with all laws and relevant industry standards, and by enhancing their value by adding connections and augmenting capacity
- Promoting the use of natural gas as the most environmentally friendly fossil fuel and a cost competitive, convenient energy source for most consumers
- Positively changing the regulatory environment so that investment is encouraged, reasonable economic rewards are available to network owners and the long-term interests of gas consumers (including supply reliability and environmental benefits) are protected
- Profitably growing our business through network expansion, building new transmission pipelines, adding related gas infrastructure and by making appropriate acquisitions
- Delivering natural gas to our customers in a manner that has minimal effect on the environment
- Providing outstanding service to our retail and commercial customers that ensures a continuing growth in customer connections to our networks and increasing gas deliveries each year
- Maintaining a work environment for both our employees and our major contractor that encourages innovation and professionalism, recognises and rewards success and promotes safety

2.4 Productivity Performance

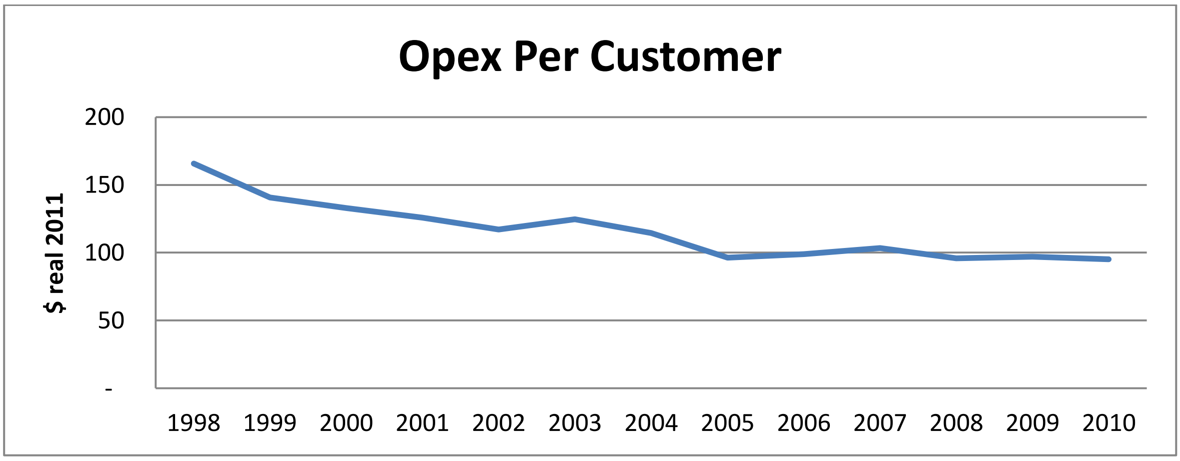
Envestra has achieved strong gains in the efficiency of its operations since it acquired the Victorian network in 1999. The improvements achieved over this period have been demonstrated through several independent and expert reports commissioned by Envestra as part of this review. In particular, these experts have found that:

- Envestra's overall productivity level is higher than its peers across Australia; and
- Envestra's total cost performance lies within the lower to middle range for most key indicators of performance relative to its peers in Australia and New Zealand.

With regard to the first point, the Victorian distributors engaged Economic Insights to undertake a comparison of their relative productivity levels with three other distributors. The analysis showed that Envestra has considerably higher productivity levels relative to all the distributors included in the sample. That is, Envestra was found to be the most efficient Victorian distributor and had productivity levels superior to all other distributors included in the sample.

These efficiency gains have been passed through to customers through lower prices. For example, operating expenditure (opex) per customer in 2010 is around 43% lower than the equivalent estimate used to set tariffs in 1998 (see figure 2.4). This reduction has been directly passed through to consumers.

Figure 2.4: Operating Cost Per Customer in Victoria, 1998 to 2011



The major factor contributing to Envestra's superior productivity performance is its outsourcing arrangement, which as noted earlier allows Envestra to access the expertise and economies of scale and scope of a significantly larger business. This strategy has led to Envestra achieving efficient cost outcomes and explains why the network has continually set industry best practice levels of performance.

2.5 Key Issues

The Victorian network is an important part of Envestra's business, accounting for 45% of total revenue in 2010/11. It is vital that the key issues currently affecting the business are addressed in the upcoming review process so that Envestra can continue to deliver on its vision and the NGO of growing its business in a sustainable manner.

These key issues are outlined in the remainder of this chapter and explored in more detail throughout this AAI.

2.5.1 Transitioning to a Low Carbon Economy

On 10 July 2011 the Federal Government announced that it would be putting a price on carbon emissions to apply from 1 July 2012, with the associated legislative changes due to be proclaimed on 2 April 2012. The price of $23 for each tonne of carbon emissions is to be escalated by 2.5% a year in real terms up until 1 July 2015, after which time the carbon price will transition to an emissions trading scheme where the price will be determined by the market.

The introduction of a carbon price reflects the Government's desire to move to what it describes as a "clean energy future" by reducing greenhouse gas emissions. Envestra considers that there is a considerable role for suppliers of natural gas to assist the community achieve its objectives of reducing carbon emissions given that natural gas is more greenhouse efficient than either coal or oil. For example:

- gas hot water systems produce about one third of the emissions of electric systems;[12]
- gas heaters produce less than half of the emissions of the equivalent electric models;[13]
- gas cook tops produce less than half of the emissions of standard electric units;[14] and
- gas air conditioners produce around two thirds of the emissions of electric units.[15]

There now exists a unique opportunity to increase the utilisation of Envestra's networks by promoting natural gas as a readily available and low cost way to improve environmental outcomes.

This will assist Envestra to address environmental objectives and the observed long term decline in average consumption, particularly among domestic consumers (see section 2.4.4 and chapter 13). To achieve these outcomes, it will be necessary to invest in network expansions and extensions to make gas readily available to consumers and to increase investment in network development to increase the use of natural gas.

The network development initiatives proposed by Envestra to capitalise on the transition to a low carbon economy and to promote the greater use of natural gas are explained in more detail in chapter 6 of this AAI.

2.5.2 Managing the Uncertainty in Global Financial Markets

As noted earlier, the GFC had significant impacts on the availability and cost of both debt and equity. Those effects are continuing with significant volatility/uncertainty remaining in global capital markets, particularly among the Eurozone.

12 George Wilkenfeld and Associates (2009), "Regulation Impact Study for Phasing out Greenhouse Intensive Water Heaters in Australian Homes".
13 WA Office of Energy (2010), "Running costs and greenhouse gas emissions".
14 Commonwealth Government (2008), Energy use – Technical Manual.
15 Origin Energy (undated), "Benefits of Natural Gas Powered Air Conditioning".

Like most businesses, Envestra responded to the GFC by deferring expenditure where this would not, at least in the short term, compromise network safety and reliability. The lower expenditure levels are however not sustainable over the long term, and as such, Envestra has already commenced restoring expenditure to required levels (particularly in regard to our mains replacement program).

A critical part of repairing the damage caused by the GFC will be to ensure that the regulated rate of return is sufficient to encourage the necessary increase in investment that is now required. As shown by the GFC, differences in regulated rates of return and prevailing market conditions can lead to significant reductions in expenditure that are not, if sustained, consistent with the long term interests of consumers.

In setting the rate of return it is important for the AER to recognise that the repercussions of the GFC continue to be experienced around the world with ongoing subdued economic growth in the United States (US) and Europe, instability in the United Kingdom and European banking systems and unprecedented levels of default risk from sovereign governments in the developed world (e.g. Greece, Italy, Spain, Ireland and the US)[16].

Systemic risk is significantly higher since the commencement of the GFC relative to the decades preceding it. Shareholders, businesses and banks now place a much higher value on access to capital and liquidity. To this end, Moody's noted that:

> *"Today's spreads are much wider than what otherwise might be inferred from the now low and declining default rate not only because the current economic recovery is the weakest upturn since the 1930s, but also because of the heightened default risk of sovereign governments from the developed world. A perceived reduction in the ability of sovereign governments and central banks to prevent or remedy economic downturns has boosted financial systemic risk."*[17]

The uncertainty in financial markets has flowed through to the Australian economy. This is illustrated by Moody's downgrading the credit ratings of all four of the major Australian banks in May 2011. Likewise, S&P downgraded most of the world's largest banks, including the major Australian banks, in December 2011.[18] The credit downgrades indicate higher credit costs due to the higher systematic risk associated with the global banking system.

There is little doubt that systemic risk in global financial markets remains elevated. The availability of capital, uncertainty and volatility in financial markets have increased risk premia. These impacts need to be reflected by the AER in the regulatory rate of return in order to promote efficient investment that is in the long term interests of consumers.

2.5.3 Changing Customer Relationships

The 2013 to 2017 Access Arrangement period will be the first under the new National Energy Customer Framework (NECF). The NECF will mean that distributors will have direct contractual arrangements with consumers (mostly in the form of deemed contracts) for the delivery of certain network services. Envestra will therefore need to increasingly interact directly with customers on their requests for network services rather than with retailers on behalf of that customer.

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16 Envestra notes that the extent and magnitude of these events was not foreseen by financial markets regulators (i.e. RBA, APRA), financial and economic forecasting bodies (i.e. OECD, IMF), or by Governments. Governments and regulators are required to deal with the consequences and restore investor confidence.

17 Moody's 2011, "If the Default Rate is so Low, Why are Credit Spreads So High?", Market Outlook, 30 June 2011.

18 The credit downgrades resulted from the implementation by Standard & Poor's of its revised credit ratings methodology for banks made in response to the many bank failures associated with the GFC.

The above changes will however increase costs, particularly in respect of the information technology systems required by Envestra to comply with its new obligations. The benefit of this investment is expected to further improve customer service by having Envestra focus on those customer requests/issues relating to network services while retailers focus on those areas for which they have direct control.

The NECF will require Envestra to establish call centre capabilities and related customer support systems. In addition, material changes will need to be made to the systems used by Envestra to communicate with retailers and the Australian Energy Market Operator. Such changes to IT systems are costly and account for a significant part of the increase in IT expenditure over the 2013 to 2017 Access Arrangement period (see chapter 7 for more information on these costs).

Envestra is required to incur this cost to comply with the new laws that underpin the NECF. Where possible, Envestra is planning to introduce changes over time in order to lessen the cost impact on customers. However, the timetable is largely driven by external factors, particularly the desire of State and Federal governments to synchronise customer arrangements on a national basis to the greatest extent possible.

2.5.4 Ensuring Demand Forecasts are Achievable

Envestra has consistently been unable to achieve the benchmark volumes set by regulators across all of its networks over the past 12 year period where regulation has applied.

Figure 2.4 compares actual and benchmark volumes for Envestra's "Tariff V" customers over the past 12 years. Tariff V customers are those customers who use less than 10 terajoules per year and account for the majority of Envestra's total revenue recovery. Figure 2.4 shows that actual volumes have been consistently below benchmark volumes across all of Envestra's networks. In Victoria, actual volumes have on average been 2.5% lower than benchmark levels over the 12 year period.

Figure 2.5 shows the annual and cumulative difference between actual and benchmark volumes for Tariff V customers in Victoria. Figure 2.5 shows that actual volumes have been 10,000 terajoules below the benchmarks set by the regulator since 1998. This issue has persisted over the entire period where regulatory benchmarks have been set and has been the main factor preventing Envestra from recovering benchmark revenue.

The persistent difference between actual and benchmark volumes primarily reflects that previous regulatory decisions have consistently underestimated the long term decline in average gas consumption (see figure 2.6). This trend decline reflects a range of factors, including warmer weather, increasing penetration of electric reverse cycle air-conditioners and certain government policy aimed at directing consumer behaviour (for example, by encouraging the uptake of solar water heaters in Victoria).

The pressure on average consumption is likely to be exacerbated from 1 July 2012 due to the introduction of the price on carbon. The introduction of the carbon price, along with the emergence of export parity pricing resulting from the development of Australia's LNG industry, is also expected to significantly increase the wholesale price of gas over the next 10 years.[19]

[19] The introduction of the carbon tax has seen many experts refer to gas as a "transition" fuel. It is expected that a significant increase in gas-fired electricity generation will be required in the medium term to replace the expected closure of certain coal-fired electricity generation. The resultant increased demand for gas (along with increased international demand) is expected to result in wholesale gas prices increasing threefold over the next five to 10 years.

To this end, the Australian Energy Market Operator (AEMO) recently released its latest Gas Statement of Opportunities (GSOO). The GSOO, among other things, provides projections of annual and peak day demand for Eastern and South Eastern Australia (including Victoria). AEMO notes in the GSOO that:

> *"The energy industry is currently experiencing uncertainty about future domestic gas prices. Gas prices in Eastern and South Eastern Australia have historically been low compared with prices in other developed economies. However, the construction of an export LNG industry in Eastern Australia could result in domestic gas prices rising toward parity with international prices. For instance, the Queensland Government's 2011 Gas Market Review suggests that current market price expectations and behaviour indicate a high price scenario is likely, with prices rising from current prices of approximately 3 $/GJ to 5 $/GJ, to over 8 $/GJ."*[20]

Declining average consumption is of particular concern to Envestra whose sole focus is on gas distribution, relative to those businesses that are also electricity distributors (and as such, are likely to be indifferent to any substitution away from gas towards electricity). As noted earlier, Envestra has proposed for the 2013 to 2017 Access Arrangement period several network development initiatives aimed at increasing network utilisation (see chapter 6).

The demand benchmarks set by the AER need to provide Envestra with a reasonable opportunity to recover the efficient costs of operating the network, which will in-turn promote efficient investment in the network, as required by the NGO. It is also vital that network development expenditure increase to improve gas usage in order to arrest the long term decline in average consumption (and hence reduce long term network prices to customers).

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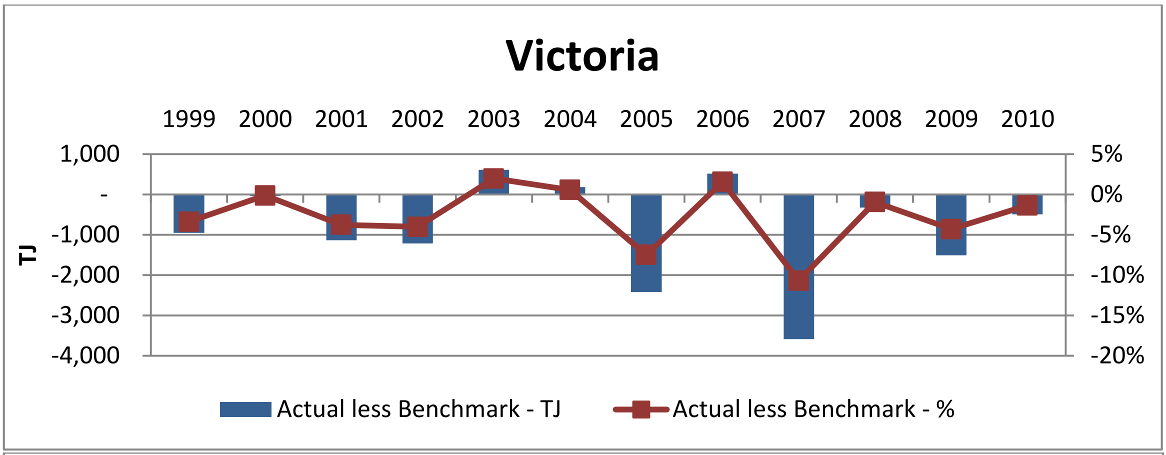
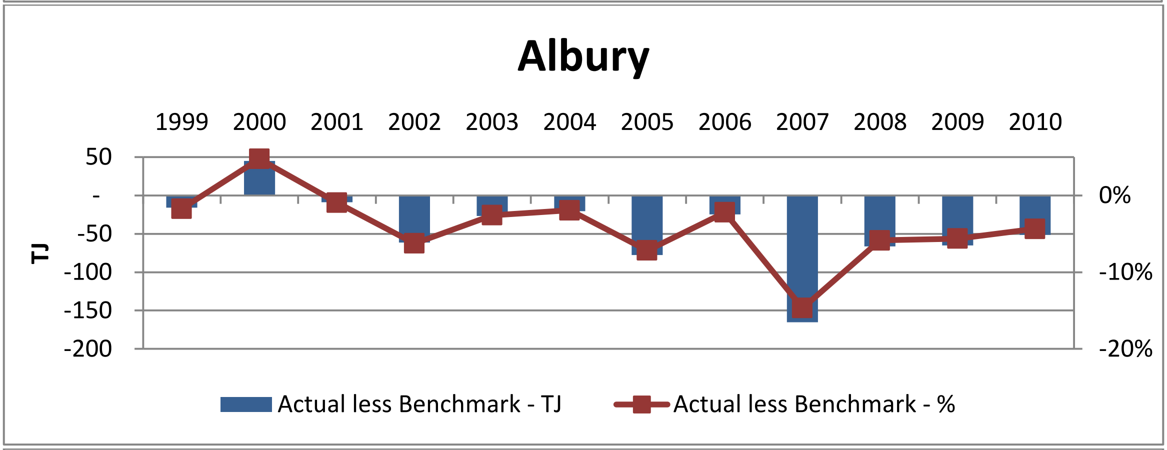
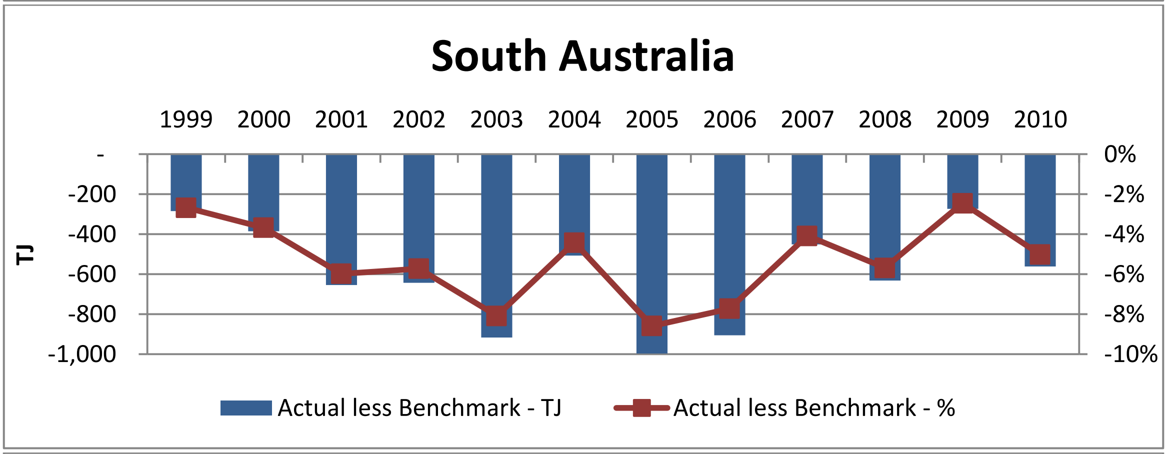
20 See: AEMO 2011, *"2011 Gas Statement of Opportunities for Eastern and South Eastern Australia"*, pg. xxxii. This document can be accessed at: http://www.aemo.com.au/planning/GSOO2011/documents/GSOO2011.pdf.

Figure 2.5: Actual less Benchmark Tariff V Volumes, All Networks







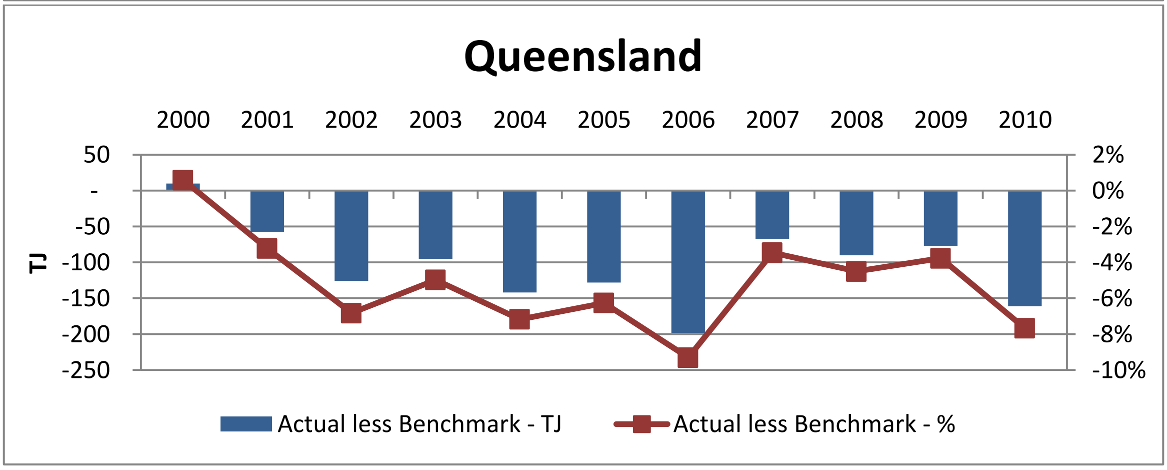


Figure 2.6: Actual less Benchmark Tariff V Volumes, Victoria (1998 to 2010)

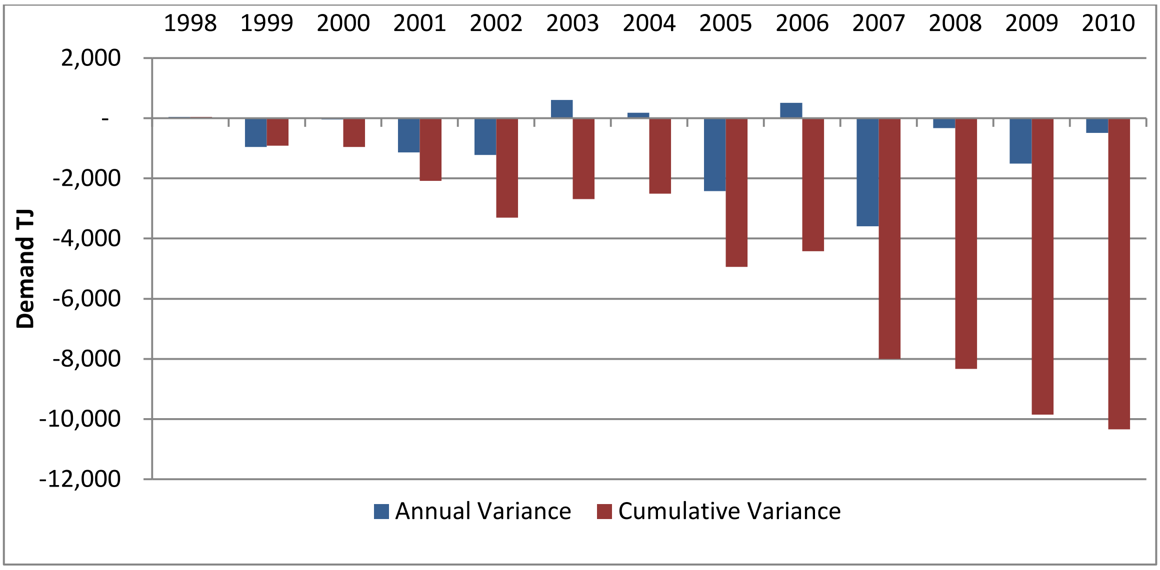
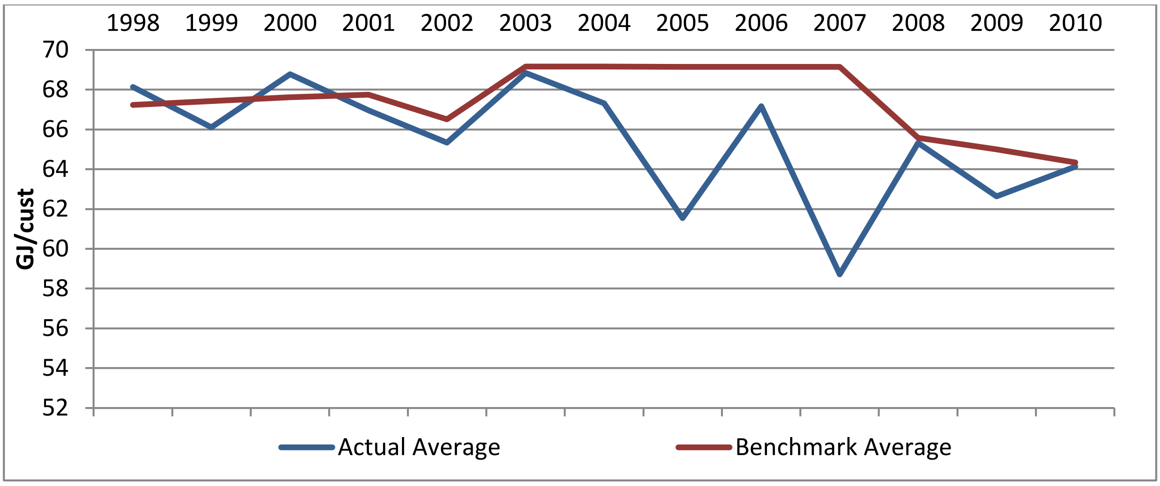


Figure 2.7: Actual and Benchmark Tariff V Average Consumption, Victoria (1998 to 2010)



2.5.5 Managing Input Price Pressures

Significant investment is required to be undertaken on the Victorian network over the 2013 to 2017 Access Arrangement period (see Chapter 7). This reflects the current industry investment cycle where assets installed some 60 years ago now need to be replaced. As discussed earlier, the increased expenditure is also required to repair the damage caused by the GFC and restore expenditure to sustainable levels.

There are a number of factors that will see an environment of increasing cost pressures persist over the 2013 to 2017 Access Arrangement period and beyond, including the:

- *Mining and Resources Boom* – significant global demand for minerals has led to unprecedented levels of investment in mining and exploration, which investment was around $62 billion in 2010/11 (reflecting the highest expenditure on record and a 50% increase from 2009/10). This level of investment is expected to increase to over $70 billion in 2011/12 and continue at these levels given the positive outlook for commodity prices over the medium term[21];

- *Nation Building Program* – the Federal Government has committed $37 billion to fund critical infrastructure in the transport, communications, water and energy sectors of the economy;

- *National Broadband Network (NBN)* – in addition to the Nation Building Program, the Federal Government has committed a further $37 billion to build a superfast NBN, which is the single largest infrastructure project in Australia's history;

- *Energy Network Renewal* – electricity and gas networks across Australia have embarked on major network refurbishment, extension and augmentation programs that are directed at improving reliability levels and addressing ageing asset profiles;

- *Coal Seam Gas* – several significant investment decisions have recently been confirmed to process coal seam gas into liquefied natural gas (LNG), which will require more than $100 billion in infrastructure investment over the next five years for extensive drilling of gas wells and the development of significant gas networks to transport gas[22],

- *Introduction of a Carbon Price* – which is expected to trigger significant investment in gas-fired power stations along with new renewable generation facilities over the next decade; and

- *Recent Natural Disasters* - the Queensland and Victorian floods in early 2011 and the more recent flood events in New South Wales requires significant investment to restore the infrastructure and building damage in those states.

The above are provided as examples only and do not fully capture the unprecedented level of investment in Australian infrastructure projected to occur over the next decade. The labour and materials required to support this investment will be of the type used by Envestra, and as such, will put significant upward pressure on labour and materials costs over the 2013 to 2017 Access Arrangement period.

2.5.6 Mains Replacement Program

In recent years Envestra has embarked on a significant long term program of replacing all of its aged mains. These aged mains are now at the end of their useful lives and under certain circumstances their failure can pose significant safety risks to gas customers, the public and operating personnel. As already noted, the impact of the GFC was to temporarily reduce Envestra's expenditure program over the 2008 to 2010 period, particularly mains replacement expenditure.

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21 See New, R, Ball, A, Copeland, A et al. 2011, "*Minerals and energy, major development projects – April 2011 listing*", ABARES, Canberra, May.

22 This includes the Australia Pacific LNG project (joint venture between Origin Energy and ConocoPhillips), Gladstone LNG (joint venture between Santos and Petronas), Queensland Curtis LNG project (British Gas Group), the Arrow Energy LNG project (Royal Dutch Shell) and the Wheatstone LNG project (joint venture between Chevron, Apache, Kuwait Foreign Petroleum Exploration Company and Shell).

Energy Safe Victoria (ESV) expressed its concerns to Envestra regarding the delay in the mains replacement program. The ESV noted that it was "significantly concerned" that the delay could potentially lead to "catastrophic failure of cast iron which puts the public and Envestra at risk." Envestra has since agreed with the ESV to restore its mains replacement program so that it is completed by 2020/21.

In line with this target, Envestra has significantly increased its mains replacement from 2010, replacing around 100 km in 2011 with plans to replace 150 km in 2012. A high level of mains replacement will continue over the 2013 to 2017 Access Arrangement period. The mains replacement program is resource intensive and will therefore comprise a significant portion of the forecast capital expenditure program (Envestra notes that it will also be restoring augmentation and IT expenditure).

Apart from providing a safer and more reliable supply of gas, the mains replacement program will provide the ancillary benefit of enhancing network capacity. This is because the new mains will be able to operate at higher pressures than those (cast iron) mains being replaced. This will enable Envestra to cater for higher peak demands than previously, including meeting the increasing capacity demands being placed on the network driven by consumer preferences for high gas consuming appliances (such as instantaneous hot water systems).

The mains replacement program is therefore a key feature and strategic component of Envestra's expenditure program over the 2013 to 2017 Access Arrangement period.

2.5.7 Australian Competition Tribunal Decisions

The Australian Competition Tribunal has recently handed down several decisions that provide clarification over the proper interpretation and application of the National Gas Law and National Gas Rules. Envestra has taken this guidance into consideration in preparing its revised Access Arrangement for the 2013 to 2017 period, particularly in respect of:

- the inclusion in the expenditure benchmarks of the margin and incentive payments paid to APA under the 2007 Operating and Management Agreement (see chapter 5);
- determining the appropriate rate of return on capital invested by Envestra (see chapter 9); and
- determining the benchmark cost of tax (see chapter 10).

2.6 Summary

Envestra's vision is to own and reliably operate natural gas networks, pipelines and related services that generate attractive returns to its shareholders. Achievement of this vision requires efficient network growth, strong customer service and improved environmental outcomes. A key strategy to achieve this vision is Envestra's outsourcing structure, which allows Envestra to achieve efficient cost outcomes that are consistent with good industry practice.

Envestra's outsourcing strategy is supported by the expert evidence prepared as part of this Access Arrangement review. This evidence demonstrates that Envestra is a highly efficient distributor, with overall productivity levels higher than its industry peers. These efficient cost outcomes have been continually passed through to customers over the past 10 years of Envestra network ownership in Victoria.

A primary focus over the 2013 to 2017 Access Arrangement period is to restore capital expenditure, particularly mains replacement, augmentation and IT expenditure, to required levels that will ensure the efficient and reliable provision of network services to consumers over the long term. Envestra is also focussed on improving the utilisation of the network through the successful implementation of network development programs aimed at promoting the greater use of natural gas.

The implementation of these business strategies will provide long term benefits for customers by improving the robustness of the distribution network (including its reliability), improving customer service and providing a greater number of Victorians with access to the natural gas distribution network. As the carbon intensity of natural gas is the lowest of all fossil fuels, the increased use of gas will also improve environment outcomes.

Realisation of Envestra's business strategies, including assisting Australia move to a low carbon economy, will require increased investment that will lead to higher costs over the short term. However, many of the drivers of higher costs reflect either necessary one-off adjustments (e.g. the carbon price) or are reflective of current industry and economic circumstances (e.g. the replacement of ageing assets and the introduction of NECF). These are well known and accepted factors impacting on Envestra's business (and others) at this point in time.

Importantly, while the coincidence of these factors will result in higher prices over the 2013 to 2017 Access Arrangement period, Envestra expects prices over the long term to moderate as these cost drivers dissipate (for example, following completion of the mains replacement program). This AAI provides extensive information and explanation demonstrating the need for and efficiency of the costs expected to be incurred by Envestra over the 2013 to 2017 Access Arrangement period.

3. Past Performance

3.1 Introduction

The National Gas Rules (NGR) sets out the specific requirements that an Access Arrangement Information (AAI) must contain. This chapter provides the information required by the NGR of an AAI as it relates to Envestra's operating and capital expenditure over the 2008 to 2012 Access Arrangement period.

In particular, this chapter outlines Envestra's actual operating and capital expenditure relative to the benchmarks set by the then regulator, the Essential Services Commission of Victoria (ESCV), for the 2008 to 2012 Access Arrangement period, including an outline of key variances. Also discussed is Envestra's demand and revenue past performance compared to the benchmarks that were set by the ESCV.

This chapter also discusses Envestra's productivity performance over the past 10 year period. This includes a discussion of the rate of change in productivity over this period and also Envestra's absolute (or overall) productivity levels. These productivity comparisons are made relative to Envestra's industry peers.

3.2 Data

The information used in this chapter, and Envestra's AAI more generally, is based on Envestra's audited accounts for the 2008 to 2010 period and the best available actual/forecast information for the 2011 and 2012 years.

Given the timing of preparation of this AAI it was not possible to include actual information for 2011 and 2012. Therefore, 2011 expenditure, demand and revenue estimates are based on 9 months of actual and 3 months of forecast information, while 2012 is based on the best available forecast information. For ease of reference, the AAI in some cases refers to 2011 and 2012 information as "actual information" over the 2008 to 2012 Access Arrangement period.

The 2011 information will be updated in response to the Draft Decision using actual audited costs. At that time Envestra will also update the 2012 information using the most recent forecast information available.

3.3 Operating Expenditure

This section addresses the requirement of rule 72(1)(a)(ii) of the NGR for the AAI to include "operating expenditure (by category) over the earlier access arrangement period". This section compares actual and benchmark operating expenditure over the 2008 to 2012 Access Arrangement period.

3.3.1 Actual and Benchmark Operating Expenditure

Tables 3.1 and 3.2 show that Envestra's actual operating expenditure is expected to be around $7 million (or 3%) below that allowed for by the ESCV. This positive outcome highlights the efficient cost outcomes that Envestra has continued to achieve over the 2008 to 2012 Access Arrangement period. The cost efficiencies are attributable to our operating structure (see chapter 5) and strict cost management during difficult economic conditions (see chapter 2).

Table 3.1: Envestra's Actual Operating Expenditure, 2008 to 2012

$m (2011)	2008 actual	2009 actual	2010 actual	2011 forecast	2012 forecast	Total
Operating Costs						
Network Operating Costs	3.8	3.8	3.8	3.8	3.9	**19.1**
Billing and Revenue Collection	1.0	1.0	0.3	0.4	0.4	**3.1**
Network Development	1.2	0.5	1.3	2.4	2.9	**8.3**
Regulatory Costs	0.9	0.6	0.4	1.2	1.2	**4.4**
Other Operating Costs	31.0	31.8	33.0	32.1	31.9	**159.8**
Total Operating Costs	**37.8**	**37.7**	**38.7**	**40.0**	**40.4**	**194.7**
Maintenance Costs						
Distribution Pipelines	1.7	1.9	2.3	2.3	2.3	**10.5**
Cathodic Protection	0.5	0.6	0.5	0.6	0.6	**2.8**
Network Control	0.4	0.2	0.5	0.6	0.6	**2.4**
Other Maintenance Costs	7.8	8.6	8.0	8.9	9.0	**42.2**
Total Maintenance Costs	**10.4**	**11.3**	**11.3**	**12.3**	**12.5**	**57.8**
Total Actual / Forecast Operating Expenditure	**48.2**	**49.0**	**50.0**	**52.4**	**52.9**	**252.5**

Note: Totals may not add due to rounding.

Table 3.2: ESCV Benchmark Operating Expenditure, 2008 to 2012

$m (2011)	2008	2009	2010	2011	2012	Total
Operating Costs						
Network Operating Costs	3.5	3.6	3.7	3.7	3.8	**18.3**
Billing and Revenue Collection	0.1	0.1	0.1	0.1	0.1	**0.6**
Network Development	2.8	2.8	2.9	2.9	2.9	**14.3**
Regulatory Costs	0.9	0.9	1.0	1.0	1.0	**4.8**
Other Operating Costs	32.7	33.3	34.0	34.6	35.3	**169.8**
Total Operating Costs	**40.0**	**40.8**	**41.6**	**42.3**	**43.1**	**207.8**
Maintenance Costs						
Distribution Pipelines	2.9	4.0	2.6	2.1	2.1	**13.7**
Cathodic Protection	0.5	0.5	0.5	0.6	0.6	**2.7**
Network Control	0.4	0.4	0.4	0.4	0.4	**1.8**
Other Maintenance Costs	6.5	6.6	6.7	6.9	7.0	**33.7**
Total Maintenance Costs	**10.3**	**11.5**	**10.2**	**9.9**	**10.0**	**52.0**
Total Approved Operating Expenditure	**50.3**	**52.3**	**51.8**	**52.3**	**53.2**	**259.8**

Note: Totals may not add due to rounding

3.3.2 Variations from Regulatory Benchmarks

This section outlines the key variations between actual and benchmark total operating costs and total maintenance costs over the 2008 to 2012 Access Arrangement period.

3.3.2.1 Total Operating Costs

Figure 3.1 compares actual and benchmark total operating costs for the 2008 to 2012 Access Arrangement period. Actual total operating costs are expected to be around $13 million (or 6%) less than that allowed for by the ESCV.

Figure 3.1: Actual and Benchmark Total Operating Costs, 2008 to 2012

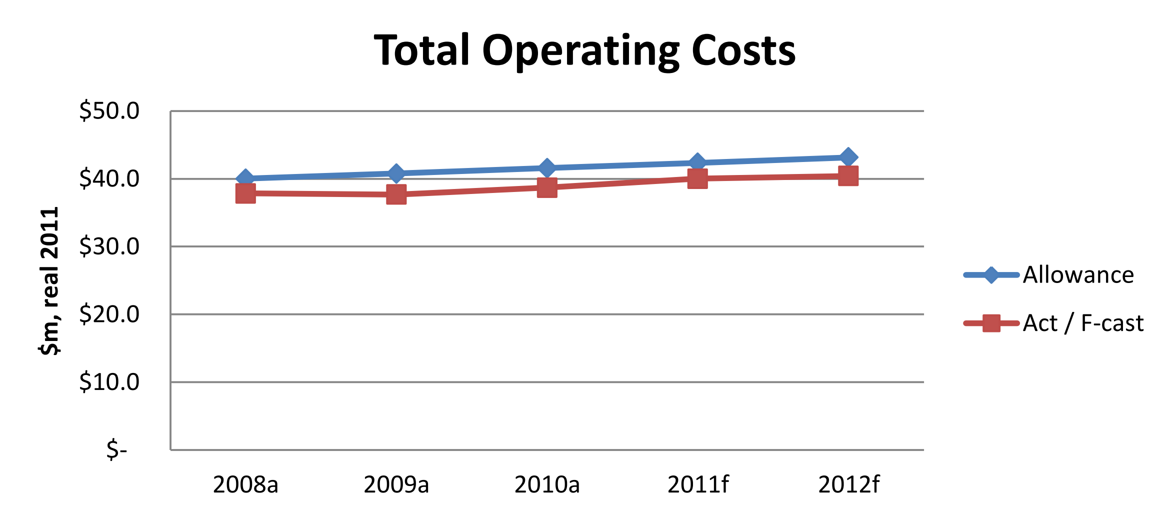


Table 3.3 compares actual and benchmark expenditure for each category of total operating costs. The key driver of the reduction in total operating costs reflects the curtailment of network development expenditure during the global financial crisis (GFC).[23] As noted in chapter 2, network development was reduced during the GFC as it was identified as one of the few operating activities that could be reduced without compromising network safety and reliability.

Envestra has since restored network development expenditure to required levels as the worst of the GFC has passed.

Table 3.3: Actual and Benchmark Total Operating Costs by Category

$m (2011)	5 year Actual	5 year Benchmark	Variance $
Network Operating Costs	19.1	18.3	0.8
Billing and Revenue Collection	3.1	0.6	2.5
Network Development	8.3	14.3	-6.0
Regulatory Costs	4.4	4.8	-0.4
Other Operating Costs	159.8	169.8	-10.0
Total Operating Costs	**194.7**	**207.8**	**-13.2**

[23] The variance in billing and revenue collection reflects that FRC costs are now integrated across the business rather than accounted for separately as was the case in setting the billing and revenue benchmark. The variance in other operating costs reflects a number of minor variances across the costs included in this category.

3.3.2.2 Total Maintenance Costs

Figure 3.2 compares actual and benchmark total maintenance costs for the 2008 to 2012 Access Arrangement period. Actual total maintenance costs are expected to be around $6 million (or 11%) above the benchmarks set by the ESCV.

Figure 3.2: Actual and Benchmark Total Maintenance Costs, 2008 to 2012

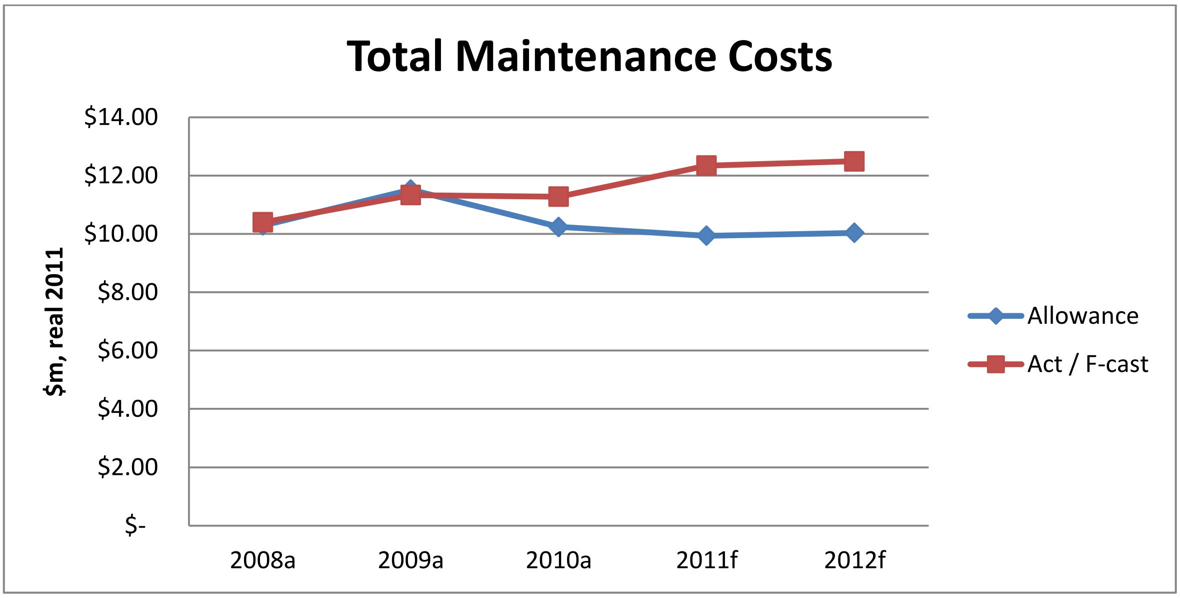


Table 3.4 compares the actual and benchmark expenditure for each category of total maintenance costs. The higher than benchmark total maintenance costs primarily reflects increases in:

- *leak repair costs* (included in "other maintenance costs") – the continued deterioration of old mains led to an increase in the number of leaks that needed to be repaired. The challenging environmental conditions also triggered a significant increase in the number of water-in-mains incidents, with a commensurate increase in restoration and repair costs; and
- *Regulatory obligations* (included in "other maintenance costs") – increasing environmental control obligations and traffic management costs driven by changes to State and Local Government laws has had a material impact on the cost of maintenance activities over the period.

Table 3.4: Actual and Benchmark Total Maintenance Costs by Category

$m (2011)	5 year Actual	5 year Benchmark	Variance $
Distribution Pipelines	10.5	13.7	-3.3
Cathodic Protection	2.8	2.7	0.1
Network Control	2.4	1.8	0.5
Other Maintenance Costs	42.2	33.7	8.5
Total Maintenance Costs	**57.8**	**52.0**	**5.8**

3.4 Capital Expenditure

This section addresses the requirement of Rule 72(1)(a)(i) of the NGR for the AAI to include "capital expenditure (by category) over the earlier access arrangement period". This section compares actual and benchmark capital expenditure over the 2008 to 2012 Access Arrangement period.

3.4.1 Actual and Benchmark Capital Expenditure

Tables 3.5 and 3.6 shows that actual capital expenditure will be around $127 million (or 29%) below that allowed for by the ESCV. Most of the reductions in expenditure during the GFC were made to capital expenditure, which primarily explains the larger reductions in capital expenditure relative to operating expenditure.

Table 3.5: Envestra's Actual Capital Expenditure, 2008 to 2012

$m (2011)	2008 actual	2009 actual	2010 actual	2011 forecast	2012 forecast	Total
Mains Replacement	7.3	2.8	6.5	22.8	33.0	**72.4**
Ad hoc Mains Replacement	2.4	1.6	1.8	1.4	2.1	**9.2**
Residential Connections	28.9	25.9	26.4	30.4	26.5	**138.1**
Commercial / Industrial Connections	3.6	3.0	2.5	2.6	5.1	**16.9**
Augmentations	2.5	6.7	7.7	3.7	16.3	**36.8**
IT	0.3	0.1	1.4	3.4	0.5	**5.7**
Residential Meter Replacement	2.8	2.0	2.7	2.9	3.1	**13.4**
Commercial / Industrial Meter Replacement	1.0	0.6	0.6	0.7	1.4	**4.2**
Other	3.2	0.3	2.5	1.0	1.6	**8.6**
Gas Extensions - NGEP	1.6	0.4	0.1	0.1	0.8	**3.0**
Gas Extensions - Other	1.5	1.7	3.4	5.5	3.8	**15.8**
Customer Contributions	-0.4	-0.7	-1.8	-3.4	-1.9	**-8.1**
Government Contributions	-1.5	0.0	0.0	0.0	0.0	**-1.5**
Total	**53.1**	**44.4**	**53.5**	**71.2**	**92.2**	**314.3**

Note: Totals may not add due to rounding

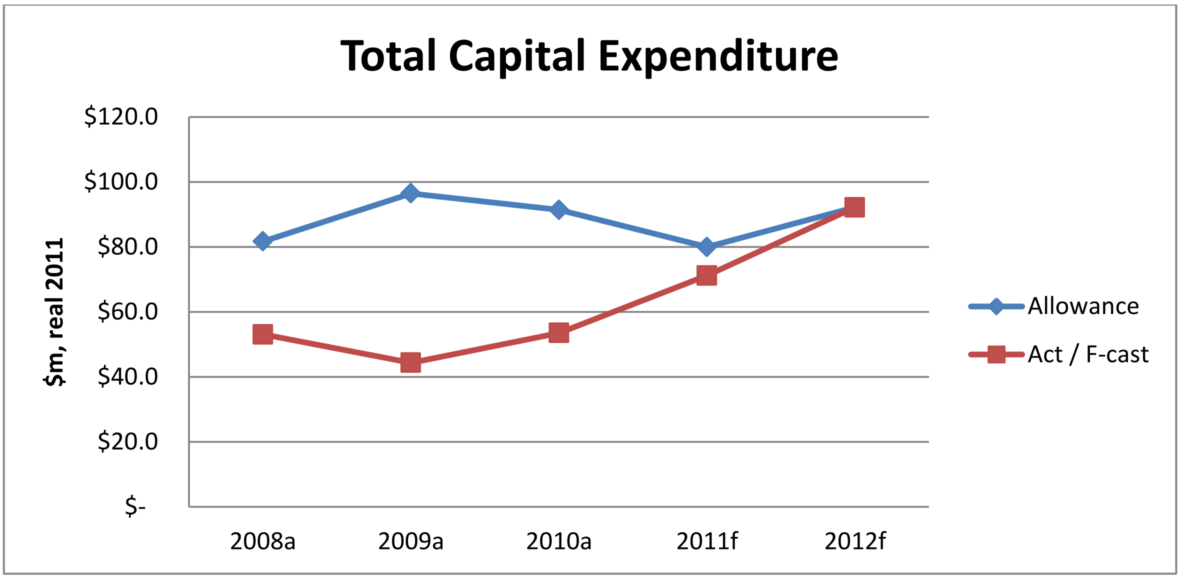
Table 3.6: ESCV Benchmark Capital Expenditure, 2008 to 2012

$m (2011)	2008	2009	2010	2011	2012	Total
Mains Replacement	17.3	19.9	22.9	25.9	33.0	**118.9**
Ad hoc Mains Replacement	1.9	1.9	2.0	2.0	2.1	**9.9**
Residential Connections	22.8	24.9	26.0	26.6	24.8	**125.1**
Commercial / Industrial Connections	3.8	3.8	4.6	5.1	5.1	**22.5**
Augmentations	10.6	27.5	15.4	8.3	16.3	**78.0**
IT	12.9	6.6	7.6	0.4	0.5	**27.9**
Residential Meter Replacement	4.8	5.6	5.5	3.5	3.1	**22.5**
Commercial / Industrial Meter Replacement	1.5	1.3	1.2	1.3	1.4	**6.7**
Other	2.5	2.1	2.0	1.9	1.6	**10.0**
Gas Extensions - NGEP	2.4	1.3	0.9	0.8	0.8	**6.2**
Gas Extensions - Other	2.1	1.8	3.5	4.3	3.8	**15.5**
Customer Contributions	-0.2	-0.2	-0.2	-0.2	-0.2	**-1.0**
Government Contributions	-0.6	0.0	0.0	0.0	0.0	**-0.6**
Total	**$81.7**	**$96.5**	**$91.4**	**$80.0**	**$92.2**	**$441.7**

Note: Allowed Capital Overheads have been allocated across expenditure categories on a pro-rata basis. Totals may not add due to rounding.

Figure 3.3 compares actual and benchmark capital expenditure, which illustrates that the reductions in capital expenditure were highest over the 2008 to 2010 period, corresponding with the worst period of the GFC. Envestra notes that while global uncertainty remains, particularly due to ongoing economic issues in Europe, the constraints on raising capital are not as severe as they were during the GFC. This explains the increase in expenditure to towards benchmark levels in 2011 and 2012.

Figure 3.3: Actual and Benchmark Capital Expenditure, 2008 to 2012



3.4.2 Material Variations in Capital Expenditure

Table 3.7 compares actual and benchmark expenditure for each category of capital expenditure over the 2008 to 2012 Access Arrangement period.

Table 3.7: Actual and Benchmark Capital Expenditure by Category

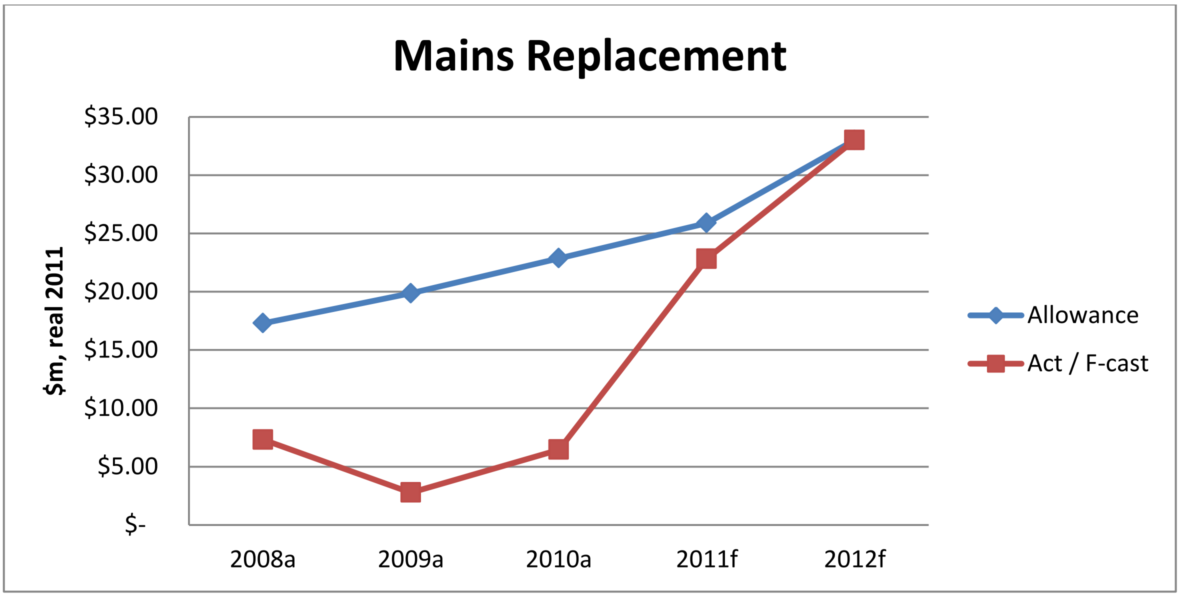
$m (2011)	5 year Actual	5 year Benchmark	Variance $
Mains Replacement	72.4	118.9	-46.5
Ad hoc Mains Replacement	9.2	9.9	-0.7
Residential Connections	138.1	125.1	13.0
Commercial / Industrial Connections	16.9	22.5	-5.6
Augmentations	36.8	78.0	-41.3
IT	5.7	27.9	-22.2
Residential Meter Replacement	13.4	22.5	-9.1
Commercial / Industrial Meter Replacement	4.2	6.7	-2.5
Other	8.6	10.0	-1.4
Gas Extensions - NGEP	3.0	6.2	-3.2
Gas Extensions - Other	15.8	15.5	0.4
Customer Contributions	-8.1	-1.0	-7.1
Government Contributions	-1.5	-0.6	-0.9
Total	**314.3**	**441.7**	**-$127.4**

As previously noted, the GFC led to significantly higher debt and equity finance costs and reduced the availability of finance to levels that were not anticipated when business plans underpinning the 2008 to 2012 Access Arrangement were put in place. The GFC prevented Envestra from completing its planned capital expenditure program, although expenditure levels are now returning to required levels (as shown in figure 3.3).

One of the key areas of our capital expenditure program that was deferred related to the mains replacement program. Figure 3.4 compares actual and benchmark mains replacement expenditure, which shows that actual expenditure is expected to be around $47 million (or 39%) less than the regulatory benchmark.

While prudent during the GFC, the deferral of the mains replacement program is not sustainable over the long term. Indeed, Energy Safe Victoria raised its concerns with the deferral of Envestra's mains replacement program and its potential implications for public safety and ongoing network reliability. Envestra has since committed to a mains replacement program that addresses the concerns of Energy Safe Victoria.

Figure 3.4: Actual and Benchmark Mains Replacement, 2008 to 2012



Another key variance in capital expenditure relates to expenditure on commercial and industrial connections, which is expected to be almost $6 million (or 25%) lower than benchmark levels. This reflects a significant drop in the number of commercial customer connections driven by the significant slow down in economic activity during the GFC (particularly when compared with the strong economic activity prior to the GFC, which growth underpinned the connection forecasts).

Like mains replacement, certain network augmentation and information technology (IT) projects were also delayed as a result of the GFC, as this was feasible in the short term without compromising network safety and reliability. Actual expenditure on network augmentation and IT is expected to be $41 million (or 53%) and $22 million (or 80%) respectively below that allowed for by the ESCV.

In respect of IT expenditure, there was also considerable uncertainty regarding the IT requirements stemming from the introduction of the new National Energy Customer Framework (NECF) during the regulatory period (see section 2.4.3). The intention of NECF is to improve customer service by having distributors directly liaise with gas consumers regarding the provision of network services.

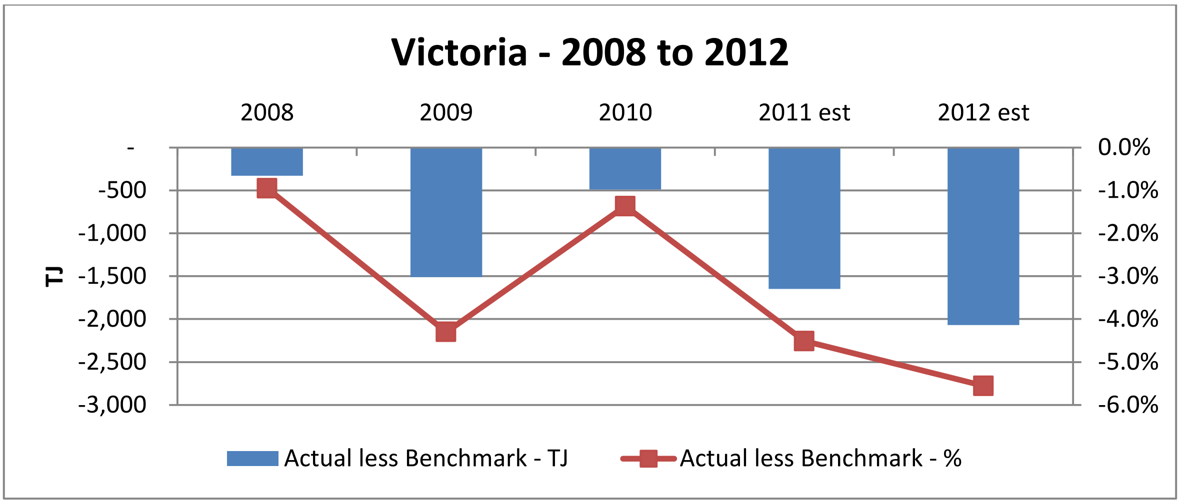
The greater clarity now provided around NECF will ensure that prudent and efficient IT expenditure is now incurred.

Finally, the reductions in residential and commercial meter replacements was mostly driven by a change in the relevant Australian Standard, which required meters to be changed every 15 years rather than every 10 years. The benchmark was based on the previous standard of replacing meters every 10 years, such that the benchmark was based on a higher forecast of meter replacements over the 2008 to 2012 Access Arrangement period.

3.5 Demand

Figure 3.5 compares actual and benchmark volumes for Envestra's Victorian "Tariff V" customers for the 2008 to 2012 Access Arrangement period. Tariff V customers include residential and commercial customers who consume less than 10 terrajoules (TJ) per year. Figure 3.5 shows that Envestra has not achieved the benchmark volumes in any year of the regulatory period, consistent with the general trend that has been observed over the past 10 years (see chapters 2 and 13).

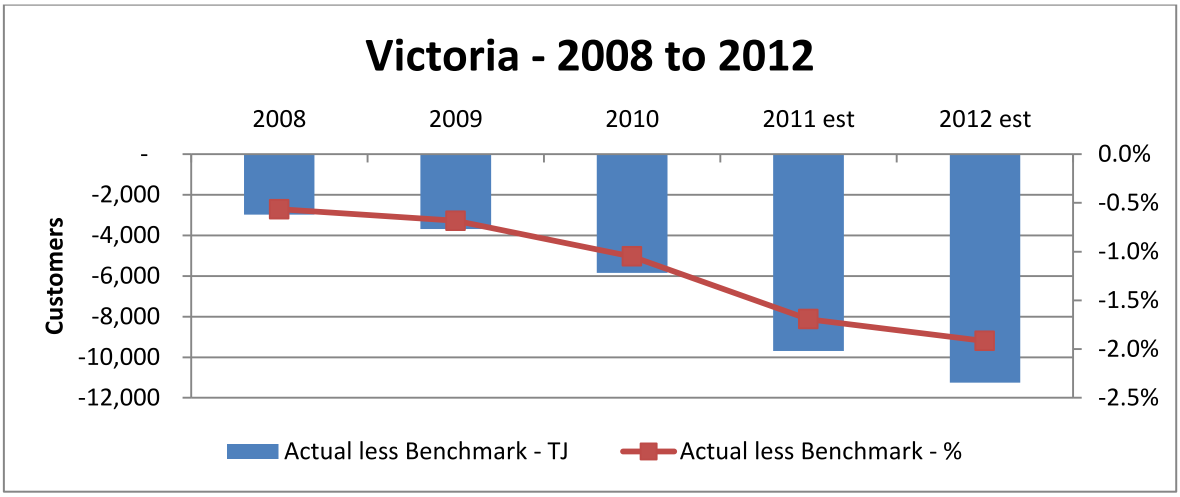
Figure 3.5: Actual less Benchmark Tariff V Volumes, 2008 to 2012



The key reason for the ongoing gap between actual and benchmark volumes reflect higher declines in actual average consumption relative to the benchmark assumptions. Declining average consumption is due to a range of factors, including the trend towards warmer weather and the shift towards electric reverse cycle air-conditioning. The rate of decline is expected to accelerate with the introduction of the carbon tax from 1 July 2012.

Figure 3.6 compares actual and benchmark Tariff V customer numbers. This shows that actual customer numbers are also expected to be lower than benchmark levels. As explained earlier, this in part reflects a slow down in economic activity brought on by the GFC, but also a shift to greater high rise apartment living, which dwellings tend not to be supplied with natural gas.

Figure 3.6: Actual less Benchmark Tariff V Customers Numbers, 2008 to 2012



3.6 Revenue

Tables 3.8 and 3.9 shows that, consistent with previous periods, Envestra has not been able to recover the benchmark revenue set by the regulator. In the current period, actual revenue recovery will be $31 million (or 4%) lower than the regulatory benchmarks that were set by the ESCV. This primarily reflects the inability of Envestra to achieve the volume and customer number forecasts set by the regulator.

Table 3.8: Envestra Actual Revenue Recovery, 2008 to 2012

$m (2011)	2008 actual	2009 actual	2010 actual	2011 forecast	2012 forecast	Total
Haulage Revenue	153.0	160.9	165.1	164.4	168.6	812.0
Ancillary Services	1.9	2.1	2.2	2.5	2.5	11.2
Total Revenue	**154.9**	**163.0**	**167.3**	**166.9**	**171.1**	**823.2**

Note: Totals may not add due to rounding

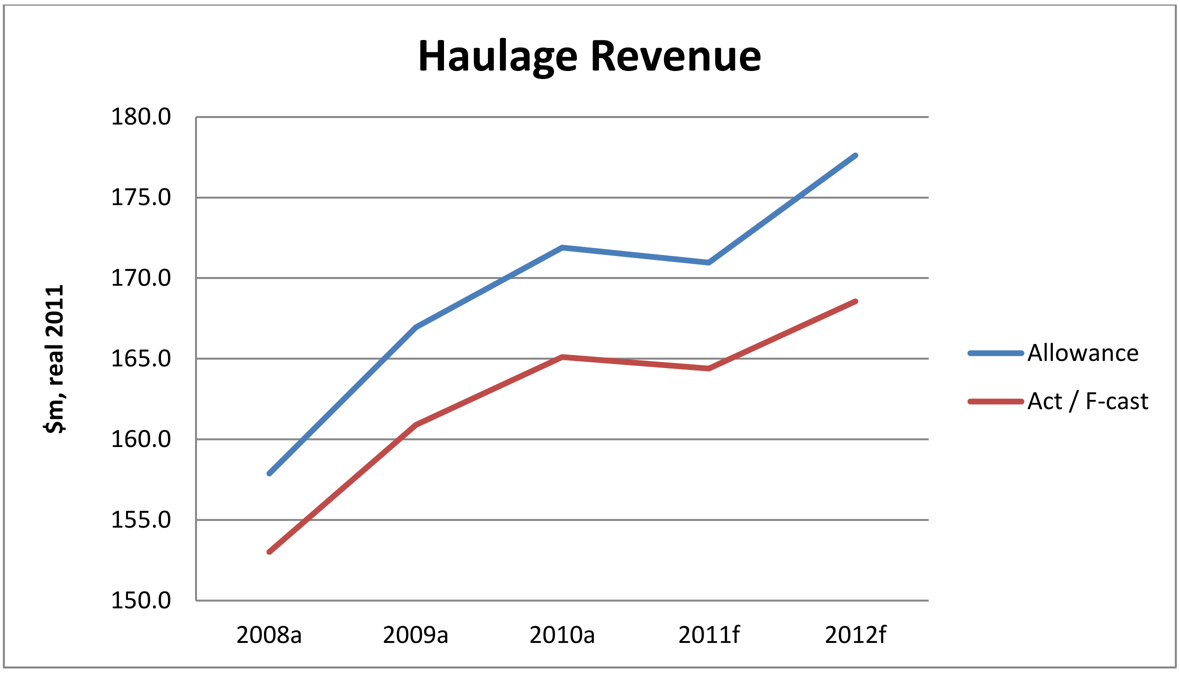
Table 3.9: ESCV Benchmark Revenue Recovery, 2008 to 2012

$m (2011)	2008	2009	20010	2011	2012	Total
Haulage Revenue	157.9	167.0	171.9	171.0	177.6	**845.3**
Ancillary Services	1.6	1.7	1.7	1.8	1.8	**8.7**
Total Revenue	**159.5**	**168.6**	**173.6**	**172.8**	**179.4**	**854.0**

Note: Totals may not add due to rounding

Figure 3.7 shows the comparison between actual and benchmark haulage revenue. Actual haulage revenue is expected to be $33 million (or 4%) lower than benchmark levels. The gap between actual and benchmark revenue has widened as the access arrangement period has progressed, consistent with the trends in benchmark volumes and customer numbers shown in figures 3.5 and 3.6.

Figure 3.7: Actual and Benchmark Haulage Revenue, 2008 to 2012



3.7 Past Productivity Performance

So far this chapter has discussed Envestra's performance relative to the expenditure, demand and revenue benchmarks set by the ESCV for the 2008 to 2012 Access Arrangement period. While this is useful in understanding how Envestra has performed (and is required to be reported by the NGR), it does not provide insight into whether Envestra is achieving efficient cost outcomes that are consistent with good industry practice.

Envestra, Multinet and SP AusNet engaged Dr Denis Lawrence of Economic Insights to undertake an analysis of the past productivity performance of the Victorian gas distributors. This analysis is set out in the report "The Total Factor Productivity Performance of Victoria's Gas Distribution Industry" (set out in attachment 3.1 to this AAI and referred to as the Economic Insights Productivity Report).

The report looks at the following three key measures of productivity:

- Total Factor Productivity (TFP) – which measures the rate of change in the ratio of total output relative to *all* inputs used;
- Partial Factor Productivity (PFP) – which measures the rate of change in the ratio of one or more outputs relative to *one* particular input (such as operating or capital expenditure); and
- Multilateral TFP (MTFP) – which measures the absolute (or overall) productivity levels of different businesses.

The TFP and MTFP measures provide a comprehensive view of overall productivity performance. This is because these measures take into account all the factors that influence productivity performance. Dr Lawrence has measured TFP across three outputs (throughput, customer numbers and system capacity) and 8 inputs (opex, lengths of transmission pipelines, high pressure pipelines, medium pressure pipelines, low pressure pipelines and services, meters and other capital).

The analysis compared the productivity performance of the three Victorian gas distributors (including Envestra) with Jemena's New South Wales gas distribution business (JGN) and Envestra's Queensland and South Australian gas distribution businesses. The comparative analysis was undertaken for the 1999 to 2009 period, which reflects the period for which data were available for all five businesses included in the sample.

Dr Lawrence was required to "normalise" the data to ensure comparability between the five distributors included in the sample. The primary adjustment made was to remove transmission mains from the data. This is because both Envestra and JGN have relatively high amounts of transmission mains given that the geographic area served by both networks is large. Government levies and unaccounted for gas has also been excluded to ensure comparability.

In regard to TFP, Dr Lawrence found that Envestra's Victorian network had the fastest rate of TFP growth over the 1999 to 2009 period:

> *"Comparing the three Victorian GDBs', JGN's and Envestra SA's TFP indexes, Envestra Victoria and SP Ausnet has the highest TFP growth for the period up to 2009 (the latest year for which data are available for all the included GDBs) with average annual growth rates of 2.4% and 2.3%, respectively. They were followed by JGN and Multinet with average annual TFP growth rates of 1.9% and 1.8%, respectively. The smaller Envestra SA had the lowest TFP growth rate at a still very reasonable 1.4%."*[24]

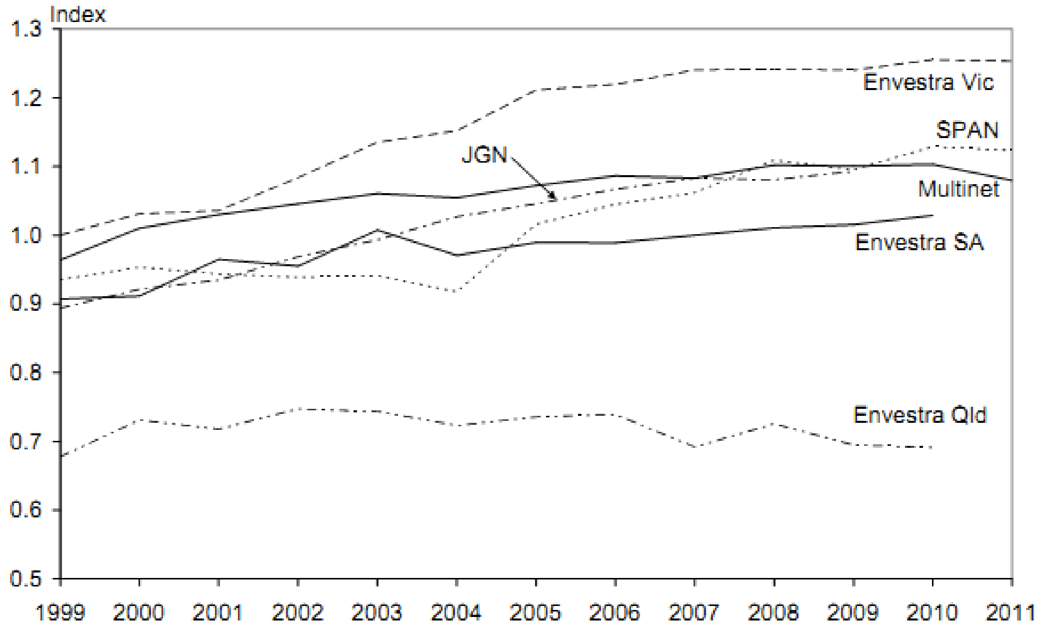
Most importantly, Dr Lawrence's analysis showed that Envestra has considerably higher overall productivity levels than all of the distributors included in the sample. Specifically, Dr Lawrence found Envestra Victoria's MTFP to be around 13% higher than SP Ausnet, Multinet and JGN (those networks in the sample not owned by Envestra). Specifically, Dr Lawrence noted that:

> *"The MTFP results indicate that the three Victorian GDBs had the highest overall productivity levels in 2009, the latest year for which data are available for all the included GDBs. When transmission-equivalent inputs are excluded, Envestra Victoria has had the highest TFP level of the five included GDBs by a 12.6% margin in 2009. It also had the highest TFP level for all of the 13 year period. In 2009 Multinet and SP AusNet were second and third placed and were followed closely by the much larger JGN. By 2011 SP AusNet's TFP level had moved ahead of Multinet's by 4%. Envestra SA achieved good productivity levels in 2009 despite having the lowest overall energy density and a domestic energy density that is comparable to JGN's but less than 40% those of the three Victorian GDBs."*[25]

The MTFP results are shown in figure 3.8 (which figure is taken from figure 6.2 in the Economic Insights Productivity Report). The results are presented relative to Envestra's Victorian network having a value of one. Figure 3.8 shows that not only has Envestra had higher productivity levels than its peers over the entire 1999 to 2011 period, but the productivity gap has continued to widen over the period.

24 Economic Insights Productivity Report, page 49.
25 Economic Insights Productivity Report, pages 44-45.

Figure 3.8: Australian GDB multilateral TFP indexes, 1999-2011



The results of the productivity analysis over the 1999 to 2009 period provides compelling support for Envestra's outsourcing structure, which allows Envestra to achieve efficient cost outcomes by leverage off the economies of scale, scope and know-how of a considerably larger business (see chapter 5). Overall, Envestra achieves efficient actual cost performance that is consistent with good industry practice and the requirements of the NGR.

3.8 Summary

Envestra's actual operating and capital expenditure is expected to be below benchmark levels over the 2008 to 2012 Access Arrangement period, particularly in the case of capital expenditure.

The reduction in capital expenditure was a necessary and prudent response by Envestra to manage the significant impacts of the GFC on the levels and availability of finance, particularly over the 2008 to 2010 period. Envestra has started to increase its capital expenditure to levels commensurate with long term business requirements (see chapter 7).

A potential benefit to Envestra from deferring capex is that financing costs are lower than anticipated by the Regulator. However, Envestra's actual volumes over the Access Arrangement period were below regulatory benchmark, a trend that has persisted over the past 10 years where volumes have been around 2.5% (on average) below benchmarks levels. This volume outcome reflects the fact that actual average consumption, particularly for residential customers, has fallen at faster rates than that assumed by the Regulator in the current, and previous regulatory periods (see chapter 13).

These lower volume outcomes have resulted in actual haulage revenue being around $33 million lower than benchmark haulage revenue. This reduction in revenue recovery has offset any benefit that Envestra might have received as a result of actual capital expenditure being below benchmark levels, which amount Envestra has estimated to be around $26 million over the 2008 to 2012 Access Arrangement period.

While benchmark comparisons are useful, it does not provide insight as to whether Envestra is achieving efficient cost outcomes. To test this, Envestra engaged Dr Lawrence of Economic Insights to determine Envestra’s productivity levels relative to its industry peers. Dr Lawrence has considerable expertise in analysing productivity levels, having advised government bodies, regulators and industry over a number of years.

The analysis undertaken by Dr Lawrence found in respect of Envestra that it has:

- the highest overall productivity levels relative to its industry peers;
- had the highest productivity levels over the entire 1999 to 2008 period (the period where actual data are available for all businesses in the sample); and
- the highest rate of growth in productivity over the 1999 to 2009 period.

In short, the analysis by Dr Lawrence found that Envestra achieves efficient cost outcomes that are consistent with good industry practice.

4. Pipeline Services

4.1 Introduction

The National Gas Rules (NGR) require Envestra to define in its Access Arrangement proposal the type and nature of pipeline services to be provided. Pipeline services include Reference Services and Non-Reference Services, where the former reflects those services that are likely to be sought by a significant part of the market. Reference services comprise Haulage Reference Services and Ancillary Reference Services.

This chapter describes the pipeline services to be provided by Envestra over the 2013 to 2017 Access Arrangement period.

4.2 Requirements of the National Gas Rules

Rule 48(1) of the NGR provides that a full Access Arrangement must describe the pipeline services that the distributor proposes to offer. Similarly, Rule 101 of the NGR states that a full access arrangement must specify all reference services, where a reference service is likely to be sought by a significant part of the market.

These requirements of the NGR are set out in sections 2.2 and 2.3 of the proposed Access Arrangement and explained in the remainder of this chapter.

4.3 Haulage Reference Services

Envestra has historically provided, and currently provides, the following two Haulage Reference Services in Victoria:

- *Tariff D Haulage Reference Service* – which provides for the firm haulage of gas to a Delivery Supply Point (DSP) with a consumption that exceeds 10 terrajoules per year or 10 gigajoules per hour; and

- *Tariff V Haulage Reference Service* – this service applies to all other DSPs.

The Haulage Reference Services include:

- receiving gas injected from a different transmission/distribution pipeline (referred to as a Transfer Point);

- odorisation of gas where required;

- haulage (or transport) of gas from a Transfer Point to a DSP;

- allowing the withdrawal of gas at a DSP; and

- for Tariff V Haulage Reference Services, meter reading and associated data services every two months, and the provision and maintenance of a standard metering installation (this being the least overall cost, technically acceptable meter and associated equipment that is able to measure and record the quantity of gas that is reasonably expected to be consumed by the customer at the DSP).

Envestra believes that the above Haulage Reference Services will continue to be sought by a significant part of the market during the 2013 to 2017 Access Arrangement period, and as such, propose that they continue to be provided from 1 January 2013, but with a slight change in terminology.

Envestra is proposing to introduce a residential and non-residential Reference Tariff as part of the Tariff V Haulage Reference Service (see section 14.4). In order to remove any potential confusion that might arise, Envestra is proposing for the 2013 to 2017 Access Arrangement period to refer to the above Haulage Reference Services as follows:

- *Demand Haulage Service* – which provides for the firm haulage of gas to a Delivery Point (DP) with a consumption that exceeds 10 terrajoules per year or 10 gigajoules per hour. The associated tariff will still be referred to as Tariff D; and

- *Volume Haulage Service* – this service applies to all other DPs. This service will have two associated tariffs - one for Residential Delivery Points and one for non-Residential Delivery Points.

The RIN requires Envestra to provide the annual volume (in GJ) and number of Users that sought a pipeline service that is not specified as a reference service in the access arrangement proposal. Envestra advises that there are no such services.

4.4 Ancillary Reference Services

In addition to the Haulage Reference Services, there are specific services that may be requested by a significant part of the market. Envestra is proposing to continue with the same Ancillary Reference Services that applied in the 2008 to 2012 Access Arrangement period, which are:

- *Meter and Gas Installation Test* – on-site testing to check the accuracy of a Metering Installation and the soundness of the gas installation downstream of the meter in order to determine whether the Metering Installation is accurately measuring the Quantity of Gas delivered;

- *Disconnection* – disconnection by the carrying out of work using locks or plugs at a Metering Installation in order to prevent the withdrawal of gas at the DP;

- *Reconnection* - reconnection by turning on supply by the removal of any locks or plugs used to isolate supply, performance of a safety check and the lighting of appliances where necessary;

- *Meter Removal* – removal of a meter at a Metering Installation in order to prevent the withdrawal of gas at the DP;

- *Meter Reinstallation* – reinstallation of a meter at a Metering Installation, performance of a safety check and the lighting of appliances where necessary; and

- *Special Meter Read* – meter reading for a DP that is in addition to the scheduled meter reading that forms part of the Haulage Reference Service (Special Meter Reads will be charged in accordance with location as either metropolitan or non-metropolitan).

4.5 Non-Reference Services

In certain cases a customer may require services that are different from the Reference Services, which are referred to as Non-Reference Services. Envestra will negotiate a price for each service on a case-by-case basis, where the price will depend on the specific conditions attached to the provision of the service as requested by the User or customer. Envestra will not discriminate where the same Non-Reference Service is provided to more than one User or customer.

Part B – Derivation of Total Revenue

5. Outsourcing Arrangement

5.1 Introduction

Since 2007 Envestra has outsourced the operation and management of the Victorian (and Albury) distribution network to the APA Group. Envestra does so to access the APA Group's economies of scale, scope and know-how arising from its significant operations of energy assets. By utilising APA, Envestra is able to access cost efficiencies that would not otherwise be available to Envestra, reflecting that APA owns and/or operates assets with a value three times that of Envestra's assets.

The terms of the outsourcing arrangement are set out in the 2007 Operating and Management Agreement (the 2007 OMA). The 2007 OMA represents the novation (with amendments) of an agreement originally entered into in 1999 (the 1999 OMA) between Envestra and Boral Energy Asset Management (BEAM), which entity was then part of the Boral Limited Group. At the time of its entry into the 1999 OMA, Envestra was an entity independent from the Boral Limited Group.

The terms of the 1999 OMA were based on the terms of an operating agreement between Envestra and BEAM relating to the operation of Envestra's South Australian and Queensland networks (the 1997 OMA). In 1999 Envestra's management considered that the 1997 OMA was operating efficiently, that its terms and pricing structure remained appropriate and that applying that outsourcing arrangement would be consistent with Envestra seeking to achieve the lowest sustainable costs in respect of its Victorian network.

The 1999 OMA needed to reflect an efficient cost outcome as Envestra was participating in a competitive bid process for the Victorian network on the basis of the cost structure under the 1999 OMA. Because of Envestra's experience with outsourcing since 1997, when bidding for the Victorian 'Stratus' business, Envestra was confident that the outsourcing arrangement would result in efficient cost by capturing the advantages of economies of scale, scope and know how of the Boral Group.

Under the 2007 OMA, Envestra reimburses APA its reasonable costs and expenses of operating and managing Envestra's network (subject to those costs being within approved budgets), pays a network management fee (NMF) equal to 3% of Envestra's revenue in Victoria and makes incentive payments that allow APA to retain for 12 months one third of the benefit of certain operating and capital cost reductions achieved by APA.

The NMF and incentive payments have been approved as efficient costs across all of Envestra's networks. In all cases, the NMF and incentive payments have been subject to considerable regulatory scrutiny. This chapter demonstrates that, consistent with the findings of previous regulatory reviews, Envestra's outsourcing arrangement continues to deliver efficient cost outcomes that are consistent with Envestra seeking to achieve the lowest sustainable cost.

The payments made by Envestra to APA to access cost efficiencies, being the NMF and incentive payments, are accordingly consistent with the relevant statutory regime applying to the assessment of Envestra's outsourcing arrangement. This chapter sets out the relevant statutory regime, the commercial logic for outsourcing and the evidence supporting the recovery of the NMF and incentive payments in the expenditure benchmarks over the 2013 to 2017 Access Arrangement period.

5.2 Requirements of the National Gas Rules

Chapter 1 of this Access Arrangement Information (AAI) explains the overarching principles set out in the National Gas Law (NGL) that the AER must have regard to in assessing Envestra's outsourcing arrangement. The specific matters governing the assessment of the costs incurred by Envestra under the 2007 OMA are set out in the National Gas Rules (NGR). The NMF and incentive payments are allocated by Envestra equally to operating expenditure (opex) and capital expenditure (capex).

The recoverability of the NMF and incentive payments (and all other costs incurred under the 2007 OMA) therefore needs to be assessed having regard to the criteria in rule 91 (opex) and rule 79 (capex) of the NGR. Rule 91 sets the criteria governing the recovery of opex and states:

> *"(1) Operating expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.*
>
> *(2) The AER's discretion under this rule is limited.*
>
> *Note:*
>
> *See rule 40(2)."*

As rule 91 notes the meaning of limited discretion is set out in rule 40(2). That rule provides:

> "*If the Law states that the AER's discretion under a particular provision of the Law is limited, then the AER may not withhold its approval to an element of an access arrangement proposal that is governed by the relevant provision if the AER is satisfied that it:*
>
> *(a) complies with applicable requirements of the Law; and*
>
> *(b) is consistent with applicable criteria (if any) prescribed by the Law.*
>
> *Example:*
>
> *The AER has limited discretion under rule 89. (See rule 89(3).) This rule governs the design of a depreciation schedule. In dealing with a full access arrangement submitted for its approval, the AER cannot, in its draft decision, insist on change to an aspect of a depreciation schedule governed by rule 89 unless the AER considers change necessary to correct non-compliance with a provision of the Law or an inconsistency between the schedule and the applicable criteria. Even though the AER might consider change desirable to achieve more complete conformity between the schedule and the principles and objectives of the Law, it would not be entitled to give effect to that view in the decision making process.*"

If an item of opex is expenditure that would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services, then it satisfies the applicable requirements and criteria of rule 91. Pursuant to rule 40(2), the AER *must* approve an item of expenditure if it satisfies the requirements of rule 91.

Rule 91(1) does not state that opex must be <u>the lowest</u> sustainable cost of delivering pipeline services. Expenditure falls within the rule if it is incurred by a prudent service provider acting efficiently <u>to achieve</u> the lowest sustainable cost of delivering pipeline services. The use of the word "achieve" is significant. If a service provider has undertaken expenditure which is consistent with what would be undertaken by a prudent service provider acting efficiently <u>to achieve</u> lowest sustainable cost then the expenditure is recoverable. The service provider does not have to show that the expenditure is in fact the lowest sustainable cost achievable.

Rule 79 sets the criteria governing the recovery of capex, which criteria is similar to that in rule 91. Rule 79 provides:

> "(*1) Conforming capital expenditure is capital expenditure that conforms with the following criteria:*
>
> *(a) the capital expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services;*
>
> *(b) the capital expenditure must be justifiable on a ground stated in subrule (2).*"

The grounds stated in subrule (2) include that the capital expenditure is necessary to maintain the safety and integrity of services, to meet levels of demand and to comply with regulatory obligations. These criteria are consistent with the obligations placed on APA under the 2007 OMA. Rule 79 is therefore consistent with rule 91. Rule 79 also provides that the AER has a limited discretion in assessing whether expenditure complies with rule 79. As with rule 91 (see above), the AER *must* approve an item of expenditure if it satisfies the requirements of rule 79.

5.3 History of the Outsourcing Arrangement

In 1997, Envestra was floated on the Australian Securities Exchange (ASX). It purchased the gas distribution business operations of the Boral Group in South Australia (SA), Queensland (Qld) and the Northern Territory (NT). Envestra entered into an outsourcing arrangement with the Boral Group, under which Boral would provide operating, maintenance and asset construction services to the Envestra networks in SA, Qld and the NT (the 1997 OMA).

In 1999, Envestra purchased the Victorian gas distribution business, Stratus, from the Victorian Government. Envestra entered into an outsourcing arrangement with the Boral Group for the operation of the Victorian network (the 1999 OMA).

In 2007, Origin Energy (previously Boral Energy) decided to sell various assets and operations, including its operating functions under the 1997 OMA and 1999 OMA.

The APA Group was the successful acquirer of the Origin Energy assets. The acquisition included the novation of the 1997 OMA (for SA, Qld, and NT) and the 1999 OMA (for Victoria and Albury) to APA. This was done by restating each of the 1997 OMA and the 1999 OMA as two new agreements with negotiated variations (the 2007 OMA for SA, Qld and NT and the 2007 OMA for Victoria and Albury) and then novating them to APA. Since this time Envestra has entered into another OMA with APA in respect of its recently acquired Country Energy gas distribution network in southern New South Wales (the 2011 OMA).

This section describes in more detail the history of the 2007 OMA, with a focus on the 1999 OMA and the 2007 OMA for Victoria (being the relevant OMAs for the purposes of this review).

5.3.1 The 1997 OMA – SA, Qld and the NT

Since its inception Envestra has been a dedicated asset owner with operations outsourced to a third party. The key motivation for this structure was to ensure that Envestra would act as a low cost operator by accessing the economies of a larger organisation. The outsourcing structure was therefore a fundamental part of Envestra's business strategy.

There were a number of possible options that could have been adopted in determining the appropriate manner in which to structure Envestra in 1997, including establishing:

(a) separate entities, one to own and operate the SA network and one to own and operate the Qld network; or

(b) a single entity with the internal resources to operate the SA and Qld networks; or

(c) a single entity that owned the SA and Qld networks but with the operation of those networks outsourced to an external provider.

The third option was adopted and BEAM (later changing its name to Origin Energy Asset Management (OEAM)), a Boral subsidiary, was selected as the external service provider. Envestra and BEAM entered into the 1997 OMA, which set out the terms of the outsourcing arrangement.

There were no other service providers at the time who could offer the experience or economies of scale and scope of Boral.[26] Boral was a much larger entity than Envestra and far better able to access economies of scale and scope than Envestra.[27] This was considered the most effective way in which to create a viable, cost-efficient new business that could successfully acquire assets in the deregulated energy market (which did occur).

If the second option was taken, whereby all operational staff for the two networks (plus the NT) had been transferred to Envestra, the effect of this would have been to deny Envestra access to the economies of scale, scope and "know-how" (or intangible assets) of the significantly larger and more experienced Boral Group.

The operating structure has also allowed the asset management arm to grow its intangible assets above that which would be available from servicing only Envestra's networks. This was the case with Boral (and later Origin Energy), which both had substantial operations well beyond the scale of the networks managed and operated by BEAM/OEAM for Envestra. This is also now the case with APA, who provides significant asset management services across a range of infrastructure.

5.3.2 The 1999 OMA – Victoria and Albury

The 1999 OMA was entered into in the context of the bid by Envestra for the gas network assets being privatised by the Victorian government.

26 Little affidavit, paragraph 26.

27 In 1998, Boral's revenue was $4.7 billion compared with Envestra's revenue of $0.1 billion. See Boral and Envestra 1997/98 Annual Reports.

The history of the 1999 OMA is described in the affidavit of Peter Cain, which affidavit forms attachment 5.1 to this AAI. This affidavit was originally prepared for the 2008 Gas Access Arrangement Review (GAAR). As the affidavit deals primarily with events in 1999 it remains relevant to the 2012 Victorian GAAR process.

Mr Cain was the executive primarily responsible for the negotiation of the 1999 OMA.[28]

As noted in Mr Cain's affidavit, at the time the 1999 OMA was entered into Envestra and BEAM (and Envestra and Boral) were not part of the same corporate group and were not related entities.[29] While Boral held 19.97% of the shares in Envestra[30] the remainder were held by parties independent of the Boral Group. Envestra's Board consisted of six Directors, two of whom were appointed by Boral and the remaining four of whom were independent Directors.

In short, in 1999 Envestra had an independent Board responsible to the shareholders of Envestra and not responsible to the Boral Group.

The sale of the Stratus Network was structured by the Victorian Government as a bundled distribution and retail business. Therefore a bidder, such as Envestra, who wished to acquire only the distribution business, was required to bid jointly with an entity willing to acquire the retail business. Envestra and Boral formed a consortium to bid for the bundled Stratus distribution and retail assets.

The bid price submitted by Envestra and Boral included various components, including an amount for the retail component of the business (contributed by Boral) and an amount for the distribution component of the business (contributed by Envestra). In determining the amount it could bid for the Stratus Network, Envestra gave consideration to, amongst other matters, the following:

(a) the most efficient and cost effective way of operating and managing the network;

(b) the estimated revenue and forecast growth of the network business;

(c) forecast cash flow of the network business; and

(d) having regard to the above, Envestra's ability to finance the acquisition.[31]

There were, in effect, only two options for the operation of the network: Envestra could operate the network itself or could outsource operations.[32] In-house operation of the network would have resulted in the network being operated by a stand-alone operator with no or minimal economies of scale. For the same reasons underpinning the decision to enter into the 1997 OMA, this option was not considered viable.

As noted in Mr Cain's affidavit, having regard to the market conditions prevailing in 1999:

28 Peter Cain Affidavit, paragraph 5.
29 Peter Cain Affidavit, paragraph 6.
30 22 July 1999 Prospectus, page 16.
31 Peter Cain Affidavit, paragraph 10.
32 Peter Cain Affidavit, paragraph 11.

"*12. Envestra considered that the only viable and in fact by far the most efficient way of structuring the tender was on the basis of outsourcing the operation and management to BEAM by way of the Victorian O&M Agreement. The SA and Queensland distribution assets owned by Envestra were already being operated by BEAM. Envestra considered BEAM's operation and management of those networks, pursuant to agreements with largely the same terms as the Victorian O&M Agreement, was working efficiently. The demonstrated efficiency of the outsourcing structure to BEAM meant that the structure proposed for the Victorian network was readily apparent and proven by experience to be the best structure for Envestra.*

13. Operating and managing the distribution arm of the Stratus Network in-house would have resulted in the asset management services being performed by a stand-alone operator with no, or very minimal, economies of scale. That is, a small stand alone business would have to spread head office, IT, human resources and overheads over a smaller revenue base, increasing operating costs. Further, large scale businesses are able to take advantage of the purchasing power and reduced costs they can achieve by purchasing goods and services in very large quantities, compared to that of a small stand alone business. The costs which would have been inherent in the services being provided by that stand-alone business, such as support services, administrative functions, IT, accounts functions and absorbing overheads over a small revenue base, would probably have meant that Envestra and Boral's bid would have been unsuccessful because the estimated cost of running the network would have been higher than the outsourcing model. It was the outsourcing structure which enabled the joint bid of Envestra and Boral for the Stratus Network to be successful. This enabled Envestra to formulate a bid based on higher cash flows than if the structure was a stand alone business, enabling it to bid a competitive amount for the Victorian Network."

Further, Mr Cain noted that both Envestra and Boral had a common interest in ensuring that the costs of BEAM operating and managing the Victorian network were efficient and competitive so as to maximise the probability of a successful bid.[33]

In negotiating the 1999 OMA, Envestra adopted, with some modifications, the terms of the existing 1997 OMA in place between BEAM and Envestra relating to the South Australian and Queensland networks. Envestra considered this the prudent step because the:

> "*South Australian O&M Agreement was working efficiently and there was no need to make significant changes to the terms contained in the South Australian O&M Agreement*."[34]

Mr Cain's evidence was reviewed by the ESCV as part of the 2008 GAAR. The ESCV found:

> "*The Commission is satisfied that, taking the position as it was in 1999, OEAM was likely to incur the lowest operating costs in relation to the Envestra Victorian network and that there were likely to be some savings and economies that OEAM was able to achieve that Envestra was unable to achieve at that time, given that Envestra had already outsourced the operation of its South Australian and Queensland networks to OEAM at that time*.

33 Peter Cain Affidavit, paragraphs 16-17.

34 Peter Cain Affidavit, paragraph 19.

The Commission generally accepts the evidence of Mr Cain that in 1999 OEAM was likely to be the lowest cost operator of the network and that together Boral and Envestra had an incentive to achieve the lowest operating costs."[35]

Further in respect of Mr Cain's evidence, the Essential Services Commission Appeal Panel stated:

> "*While the contemporaneous evidence regarding the Applicant's decision to enter into the 1999 OMA is limited to the decision making process and views of management, the Panel considers that the Applicant entered into the 1999 OMA with a view to achieving the lowest sustainable cost of providing services*."[36]

The history of the 1999 OMA is also discussed in the affidavit of Ian Little[37], the Managing Director of Envestra. As noted in that affidavit, Envestra's purchase of the Stratus Network was in part funded by a rights issue. Under this rights issue the CKI Group, a major Hong Kong based owner/operator of energy assets, acquired a 19.97% shareholding in Envestra. The fact that a major investor was prepared to take up a major shareholding in Envestra further supports the efficiency of Envestra's outsourcing arrangements.

Envestra notes the outsourcing assessment framework employed by the AER in the 2010 Victorian Electricity Distribution Price Review and in the 2011 GAARs of Envestra's South Australian and Queensland networks. While Envestra maintains its position that the application of "Stage 2" of the AER's framework constitutes an error, Envestra notes that the 1999 OMA passes Stage 1 of the framework.

In Stage 1 of the framework the AER considers whether an outsourcing contract passes or fails its presumption threshold. It does this by considering whether the service provider had an incentive to agree to non-arm's length terms at the time the outsourcing contract was entered into – i.e. was the contract entered into with a related party, or as part of a broader transaction, or was some other side payment or benefit conferred on the service provider.

The 1999 OMA was not entered into with a related party. At the time of negotiation of the 1999 OMA Envestra was majority owned (as to 80.03%) by independent shareholders and had a majority independent Board. The 1999 OMA was entered into against the background of a joint bid by Boral Limited and Envestra for the Stratus Network, but as explained in Mr Cain's affidavit, which was accepted by the ESCV and Appeal Panel, that bid drove Envestra and Boral to ensure that the 1999 OMA represented a cost efficient structure.

In summary:

(a) the 1999 OMA was entered into between two arm's length parties – Envestra was majority owned by independent shareholders from Boral and had a majority independent Board;

(b) the 1999 OMA was assessed by Envestra as the most efficient and cost effective structure to employ to manage the Victorian network. Entry into the contract was the action of a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services;

35 Essential Services Commission, "Gas Access Arrangement Review 2008-2012-Final Decision" page 80
36 Essential Services Commission Appeal Panel, Vic Gas Distribution Pty Ltd v Essential Services Commission, paragraph 113
37 Attachment 5.2 to this AAI.

(c) circumstances prevailing in 1999 required the 1999 OMA to represent an efficient structure in order to maximise the probability of a successful bid;

(d) the ESCV during the 2008 GAAR accepted that OEAM was likely to be the lowest cost operator and that Envestra had an incentive to achieve lowest operating costs in 1999; and

(e) the Essential Services Commission Appeal Panel found that Envestra had entered into the 1999 OMA with a view to achieving the lowest sustainable costs of providing services.

That is, the decision made by Envestra's management in 1999 to enter into the outsourcing arrangement has been accepted as one that is consistent with Envestra seeking to achieve the lowest sustainable costs.

5.3.3 The 2007 OMA - Outsourcing to APA

In February 2000 the Boral Group divested itself of its energy business (including BEAM), which led to the creation of a new listed entity, Origin Energy Limited. BEAM changed its name to Origin Energy Asset Management (OEAM). In 2007 Origin Energy sold its network operations business, pipeline assets and related interests, including OEAM and its shareholding in Envestra, to the APA Group.

In connection with that sale OEAM requested Envestra's consent to the novation of the 1999 OMA to the APA Group. Pursuant to the terms of the 1999 OMA, Envestra could not unreasonably withhold its consent to the novation.

As outlined in Mr Little's affidavit,[38] Envestra undertook significant internal analysis and negotiations with Origin and APA to determine whether it would consent to the novation. This included:

(a) establishment of a subcommittee of the Envestra Board to review the impact of the novation on Envestra;

(b) meetings with Origin and its sale advisors and APA as to the terms upon which Envestra would consent to the novation; and

(c) review of a business plan prepared by the APA Group as to the basis upon which APA would operate Envestra's networks.

The appointment of APA was conditional on Envestra being satisfied that the appointment would result in the efficient operation of the Victorian network. As stated in Mr Little's affidavit,[39] Envestra would not have given its consent to the novation of the 1999 OMA if there had been any real risk that the operation of Envestra's assets through the APA Group would have been at a higher cost or if the APA Group had been less experienced than Origin or not able to access substantial economies of scale and scope.

The APA Group had considerable infrastructure assets of its own as well as being the operator of several third party assets (see section 5.4). Envestra therefore considered the APA Group would be a cost efficient operator. Indeed the scope of APA's operations (particularly gas pipelines) is more aligned to Envestra's business of gas distribution, providing an opportunity for more targeted efficiency gains through the use of APA.

38 Paragraphs 109 to 115.
39 Paragraph 113.

As stated in Mr Little's affidavit:[40]

> "*APA's acquisition of the very substantial Origin Energy network assets resulted in APA receiving the benefit of the economies of scale and know how that OEAM had established by the operation of a national series of networks. In addition, the APA Group, being a very large participant in the energy transmission, distribution and infrastructure ownership sectors, added its own economies of scale and know how to those acquired through the acquisition of the Origin Energy network assets. This was seen as a positive by Envestra.*"

On the basis of the due diligence it undertook, in 2007 Envestra consented to the novation of the 1999 OMA to the APA Group.[41] As outlined in paragraph 112 of Mr Little's affidavit, Envestra consented to the novation because:

(a) on the basis of its due diligence it was satisfied there was no reasonable basis to withhold consent;

(b) a contract with a long-term aligned operator was consistent with the expectations of Envestra's substantial shareholders, financiers and the share market;

(c) APA was a commercially attractive operator due to its experience in gas transmission and distribution and the alignment of its businesses with Envestra's business; and

(d) economies of scale would be obtainable from APA due to the considerable scale of its operations.

Envestra, as a condition to giving its consent, required two amendments to be made to the 1999 OMA. The changes were to:

(a) amend the term of the contract to a 20 year contract – i.e. until June 2027. As originally executed the 1999 OMA did not contain an expiry date or early termination right so as to give Envestra (and its financiers) the certainty Envestra would have a long term relationship with its operator and would avoid the large transition costs of changing operators; and

(b) require APA to bear redundancy liabilities arising on the expiration of that contract term.

The novation of the 1999 OMA was effected by restating the 1999 OMA in a revised form reflecting the amendments negotiated by Envestra and then novating the contract to the APA Group.

Envestra also required the APA Group to absorb any transitional costs arising from Envestra's operator changing from OEAM to the APA Group.

When Envestra made the decision to consent to the novation of the 1999 OMA from OEAM to the APA Group, it was not related to the APA Group or the Origin Energy Group. Immediately prior to the time Envestra made the decision to consent to the novation:

(a) the APA Group held no shares in Envestra;

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40 Paragraph 108.

41 It also consented to the novation of the 1997 OMA to APA relating to the operation and management of its South Australian and Queensland networks.

(b) 83% of Envestra's shareholders were independent of Origin Energy – that is, Origin held only a 17% interest in Envestra;

(c) Envestra's largest shareholder was the CKI Group, with a 19.97% interest. The CKI Group is independent of the APA Group and the Origin Energy Group; and

(d) Envestra had a majority independent Board.

Further, to give its consent to the novation Envestra needed to obtain the consent of both its financiers and the CKI Group.[42] Those parties formed their own view about the commercial efficacy of the change and gave their consent.

In short, the decision by Envestra to consent to the novation of the 1999 OMA from OEAM to the APA Group was a decision made by an entity independent of both the APA Group and the Origin Energy Group, which decision was endorsed by a large group of domestic and international financiers, and made because both Envestra and its financiers considered that the APA Group would be a cost efficient and effective operator whose economies of scale, scope and know-how would enable Envestra to continue to operate its networks in a manner consistent with seeking to achieve lowest sustainable costs.

When it became operator, APA took up a 17% stake in Envestra by acquiring Origin Energy's interest in Envestra, which equity interest has now grown to around 33%. When the APA group took up that interest, the largest shareholder was the CKI Group, holding 19.97% of Envestra. Two of the eight members of the Envestra Board are CKI appointed directors (of the remaining 6 directors, 4 are independent and 2 are APA appointed directors).[43]

5.3.4 The 2011 OMA – Wagga Wagga

On 29 October 2010, Envestra acquired from the NSW Government the Country Energy gas network business.[44] Envestra again decided to outsource operations to the APA Group on similar terms to the 2007 OMA. Envestra considered that outsourcing would lead to the most cost efficient way of operating the Wagga Wagga network.

As Mr Little has stated:[45]

> "*Envestra continues to outsource operations on the basis that this approach provides Envestra with the advantages derived under the 1997/1999 and 2007 OMAs, namely lowest cost sustainable operations for relevant assets over the long term. In particular, leveraging off the existing APA network operations business which provides substantial economies of scale potentially allows new network assets to be operated at a very efficient cost under the extension of the operator's current activities.*"

42 Paragraph 111.
43 Ian Little Affidavit, paragraph 126.
44 The Country Energy business comprises around 1,160 km of gas distribution pipelines and 65 km of transmission pipelines in southern New South Wales, in the towns of Wagga Wagga, Tumut, Adelong, Gundagai, Culcairn, Holbrook, Henty, Temora, Walla Walla, Bombala and Cooma. The Country Energy business delivers around 3 petajoules of gas annually to 26,000 gas consumers.
45 Para 99 of his affidavit.

5.4 Background on the APA Group

The APA Group (which comprises the Australian Pipeline Trust and the APT Investment Trust) is a major listed gas infrastructure entity delivering more than half of Australia's annual gas consumption. APA has interests in more than 12,000km of natural gas pipeline infrastructure, over 2,800km of gas distribution networks and is the owner of various gas plants and facilities and interconnector systems. It employs over 1,200 people.

The following table, the details of which are taken from the 2011 annual reports of the APA Group and Envestra, shows the key metrics of each of Envestra Limited and the APA Group:

Table 5.1: Envestra and APA Group Key Operating Metrics, 30 June 2011[46]

	Envestra Limited	APA Group
Annual Revenue	$424m	$1,102m
Total Assets	$2,896m	$5,428m
Annual Capital Expenditure	$129m	$173m

In contrast to Envestra, the APA Group provides substantial asset management services in respect of gas and electricity infrastructure assets. APA owns and/or operates assets with a value in excess of $8 billion, which is around three times the value of Envestra's assets. The major assets owned and/or operated by the APA Group (excluding the Envestra assets operated by APA) are set out in table 5.2.

46 As extracted from the 2011 annual reports of Envestra Ltd and the APA Group.

Table 5.2: Assets Serviced by APA excluding those owned by Envestra

		Asset name	Asset Ownership
Gas Pipeline Assets			
NSW and ACT	T	Moomba to Sydney Pipeline (MSP)	APA
		Interconnect	APA
		Central West Pipeline (CWP)	APA
		Central Ranges Pipeline	APA
		Central Ranges Network	APA
Vic	T	Principal Transmission System (PTS)	APA
SA	T	SEA Gas Pipeline	APA (50%) and REST Superannuation Fund (50%)
		SESA Pipeline	APA
Qld	T	Roma to Brisbane (RBP)	APA
		Carpentaria Gas Pipeline (CGP)	APA
		Berwyndale to Wallumbilla Pipeline (BWP)	APA
	D	Allgas Energy Distribution System	Energy Infrastructure Investments, APA 19.9% interest
WA	T	Goldfields Gas Pipeline	APA 88.2% BBP 11.8%
		Midwest Gas Pipeline	APA 50%, Horizon 50%
		Kalgoorlie to Kambalda Lateral	APA
		Telfer Gas Pipeline	Energy Infrastructure Investments, APA 19.9% interest
		Parmelia Gas Pipeline	APA
		Wiluna Gold Gas Lateral	APA
		Cape Lambert, Dampier, Paraburdoo and YMP Gas Pipeline	Pilbara Iron
		Nifty Consumer Gas Pipeline	Birla Nifty Pty Ltd
		Plutonic Gas Lateral	Barrick Gold
		Maitland Gas Lateral	EDL Group Operations Pty Ltd
		Onslow Gas Pipeline	Horizon Power
		Burrup Fertilizer	Apache Energy Pty Ltd
		Cawse Gas Lateral	Norilsk Nickel Cawse Pty Ltd
		Cosmos Gas Lateral	Xstrata Nickel Australasia Operations Pty Ltd
		Jundee Gas Lateral	Newmont Yandal Operations Pty Ltd
		Leonora Gas Lateral	Energy Generation
		Thunderbox Gas Lateral	Norilsk Nickel Wildara NL
		Jaguar Lateral	Jabiru Metals Ltd
		Magellan Gas Lateral	Redback Pipelines Pty Ltd
		Cockburn Cement Delivery Station (Dongara Pipeline)	Origin Energy Pipelines Pty Ltd
		Woodada Receipt Facilities	Arc Energy Ltd
NT	T	Amadeus Basin to Darwin Pipeline (ABDP)	APA
		Bonaparte Gas Pipeline	Energy Infrastructure Investments, APA 19.9% interest
		Wickham Point Pipeline	Energy Infrastructure Investments, APA 19.9% interest
	D	Darwin Distribution System	APA

Table 5.2: Assets Serviced by APA excluding those owned by Envestra (continued)

Asset Name	Asset Ownership
Other Assets	
Moomba to Sydney Ethane Pipeline	Ethane Pipeline Income Fund, APA 6.1% interest
Murraylink and Directlnk electricity interconnectors	Energy Infrastructure Investments, APA 19.9% interest
Daandine and X41 power stations	Energy Infrastructure Investments, APA 19.9% interest
Tipton West and Kogan North coal seam methane processing plants	Energy Infrastructure Investments, APA 19.9% interest
Reticulated LPG System in Queensland, Northern NSW, SA and NT	Origin Energy LPG Ltd
Dandenong LNG Facility (Vic)	APA
Mondarra Gas Storage Facility (WA)	APA

5.4.1 The Relationship Between the APA Group and Envestra

In 2007 when the APA Group acquired from Origin Energy Limited its pipeline and network business it also acquired from Origin Energy Limited its 17% shareholding in Envestra. Since 2007 APA has increased its interest in Envestra to around 33% (as at 7 March 2012). This has occurred through two mechanisms. The first is the operation of Envestra's dividend reinvestment plan, which has led to an increase in APA's shareholding of approximately 2%.

The second is a 2009 rights issue undertaken by Envestra in which APA increased its equity interest in Envestra Limited from 19.1% to 30.6% (at a cost of $64 million). This rights issue was undertaken by Envestra to alleviate pressure on its financial covenants for the Victorian network, which pressure had arisen principally as a result of the impact of the global financial crisis. Standard & Poor's had placed Envestra's Victorian rating on "credit watch negative", which raised a real possibility of Envestra being downgraded below its then current rating of "BBB-".

Envestra's response was to consolidate its South Australian/Queensland and Victorian financing facilities to improve its overall financial position. Envestra's financiers, as a pre-condition to the consolidation, required Envestra to raise at least $100 million of equity during 2009.

It was not possible for Envestra as a "BBB-" rated borrower to obtain underwriting from a financial institution for the rights issue during the financial crisis. Envestra therefore approached both the CKI Group and the APA Group to act as underwriter. The CKI Group was not able to do so in a timely manner and therefore APA underwrote the issue. APA's actions as an underwriter were therefore those of a major shareholder in Envestra seeking to protect the value of its investment in Envestra, as a shareholder, during challenging financial times.

Envestra and APA were not related entities at the time of entry into the 2007 OMA. However, by virtue of its increased shareholding in Envestra as outlined above APA and Envestra are now related entities for financial reporting purposes.

APA's shareholding in Envestra does not affect the operation of the 2007 OMA, which contract is administered and operated on arm's length terms. The arm's length nature of the relationship is preserved by the following mechanisms:[47]

(a) APA's influence over Envestra through its shareholding is balanced by the 19% interest in Envestra held by the CKI Group;

(b) the Envestra Board currently has 8 Directors, four of whom (including the Managing Director) are independent Directors (i.e. independent of both APA and CKI), two of whom are APA appointed Directors (who are also Directors of APA entities) and two of whom are CKI appointed Directors. APA is therefore not in a position to control the Board of Envestra and can be out-voted on any issue by other members of the Board;

(c) the two APA Directors do not participate in any discussions and/or decisions relating to the operation of the 2007 OMA; and

(d) neither Envestra nor the APA Group nor the CKI Group are part of the same group of companies. That is, Envestra is not part of the same corporate group as its major shareholders.

5.5 The Provisions of the 2007 OMA

Under the 2007 OMA, APA operates the Victorian (and Albury) gas networks for Envestra. The services provided by APA include:

(a) managing the haulage of gas through each network;

(b) operating and maintaining each network;

(c) planning, designing and constructing network extensions;

(d) assisting Envestra with submissions to independent regulators;

(e) assisting Envestra in promoting the use of natural gas;

(f) preparing and settling with Envestra the budget for each financial year;

(g) providing Envestra with regular information on financial and other management issues;

(h) reading meters and billing retailers; and

(i) developing procedures, for approval by Envestra, in relation to billing, System Use Gas, fair market rental or value for APA's assets used for the services provided, key design parameters for any network and public relations activities.

In consideration of APA undertaking these activities, Envestra makes the following payments to APA:

(a) reimbursement of all costs and disbursements *reasonably* incurred or outlaid by APA in the performance of its obligations under the 2007 OMA, provided those costs fall within the approved budget or are incurred in the limited circumstances where APA is entitled to incur costs above the budget;

[47] Affidavit of Ian Little paragraph 126.

(b) the NMF (which is 3% of network revenue); and

(c) the incentive payments, which are payable for achieving reductions in costs of new connections and reductions in controllable costs per GJ.

Envestra is also responsible for government charges, unaccounted for gas and certain redundancy costs incurred during the term of the 2007 OMA.

The remainder of this section describes the cost management processes followed by Envestra and APA under the 2007 OMA.

5.5.1 Cost Management

The incurring of costs by APA is subject to strict cost management procedures set out in the terms of the 2007 OMA. It is not the case that Envestra simply reimburses APA any costs that APA incurs. The costs must firstly be reasonably incurred and secondly must be incurred in compliance with the cost management procedures set out in the 2007 OMA. The cost management procedures involve:

(a) setting of financial objectives – prior to the preparation of each annual budget, Envestra sets the financial objectives to be achieved by that budget. These objectives must be sufficient to ensure the continuous operation of Envestra's networks in accordance with relevant regulatory requirements, meet external debt obligations and meet reasonable investor expectations.[48] Subject to meeting the criteria in clause 8.2 of the 2007 OMA, Envestra has complete discretion as to the financial objectives it sets;[49]

(b) preparation of annual budget – APA must prepare a draft budget for review by Envestra forecasting proposed expenditure, network revenue and volumes. The budget must be approved by the Envestra Board before it is made final;[50]

(c) monthly reports – APA must report on actual and budget expenditure/revenue/volumes and any other information reasonably requested by Envestra on a monthly basis.[51] As noted in the affidavit of John Ferguson (see attachment 5.3), APA's Manager Networks, these monthly reports are very detailed and usually run to approximately 70 pages;[52]

(d) annual performance report – at the end of each year Envestra reports to APA on the performance of its obligations over that year;[53]

(e) audit of accounts – an independent audit is conducted at the end of each half year to verify the APA accounts.[54] As noted in the affidavit of John Ferguson, these audits are currently carried out by Deloitte Touche Tohmatsu and involve Deloitte's representatives spending around 10 days at APA's offices reviewing relevant records;[55]

48 2007 OMA clause 8.2.
49 2007 OMA clause 8.1.
50 Affidavit of John Ferguson, paragraphs 15-28; Affidavit of Ian Little, paragraph 24(g); 2007 OMA clause 9.
51 Affidavit of John Ferguson, paragraphs 15-28; Affidavit of Ian Little, paragraph 24(h); 2007 OMA clause 9.5.
52 Affidavit of John Ferguson, paragraph 31.
53 Affidavit of Ian Little, paragraph 24(i). 2007 OMA clause 5.2.
54 Affidavit of John Ferguson, paragraph 39; 2007 OMA clause 4.2(k).
55 Affidavit of John Ferguson, paragraph 39.

(f) record keeping – APA is required to keep sufficient records of network revenue, capital expenses and operating expenses to enable accounts to be accurately prepared and externally audited. Envestra has a right of access to these records[56]; and

(g) cost benchmarking – under clause 9.6 of the 2007 OMA Envestra has the right to benchmark APA's costs where they exceed the recoverable costs allowed by a Regulator.

Further, under clauses 3.3(e) and 3.3(f) of the 2007 OMA, APA must, except in the case of emergencies or expenditure required because of a change of law, not exceed the operating expense or capital expense component of the approved budget by more than 2% without the approval of Envestra.

In addition to the strict requirements set out in the 2007 OMA, Envestra and APA have established further cost management protocols as a matter of administrative practice. These protocols include a requirement for APA to seek Envestra's approval for:

(a) projects for demand customers with a capital cost in excess of $0.3 million per year; and

(b) any project where the capital expenditure exceeds $0.5 million per year. Where the expenditure exceeds $1 million the approval of the Envestra Board is required.[57]

5.5.2 Budget Setting

The affidavit of John Ferguson provides further detail on the process of setting the approved budget. Mr Little's affidavit confirms the accuracy of the detail provided in Mr Ferguson's affidavit.

As described in Mr Ferguson's affidavit, Envestra is required to outline its financial objectives for a financial year no later than 120 days prior to the commencement of that financial year. In or around March of each year, Envestra and APA meet to discuss these financial objectives. Following this meeting APA prepares a draft budget which is required to be submitted to Envestra not later than 60 days prior to the start of the relevant financial year.

Upon submission of the budget there are a series of meetings between senior executives of Envestra and APA. Envestra representatives at the meetings are generally Ian Little, Paul May (Envestra's Group Manager, Finance and Risk) and Andrew Staniford (Envestra's Group Manager, Commercial). APA's representatives include John Ferguson, Ken Hedley (APA's Finance Manager), Peter Gayen (APA's Commercial Manager) and state, asset and project managers as required.

The first formal meeting to discuss the budget is held in or around the first week of May of each year at which Envestra generally questions APA regarding the scope of and need for the proposed works program, the forecast costs, the risks and other associated issues with the proposed works program and the extent to which the draft budget meets the financial objectives set by Envestra.[58]

56 2007 OMA clauses 4.9 and 4.10.
57 Affidavit of John Ferguson, paras 42-44.
58 Insert affidavit material references

Mr Ferguson describes the first and subsequent meetings as follows:

> "*At the first and subsequent meetings between APA and Envestra referred to above, there is vigorous debate about the activities to be undertaken during the budget year, the volume of gas to be delivered, and the unit rates such as the cost per repair, the cost per metre for construction, the cost per correction of a leak etc. Envestra always heavily challenges any upward shift in rates and continuously presses for a reduction in rates. The Envestra representatives challenge how the rates are calculated or set and routinely require evidence for and justification of the opex and capex comprised in the budget. There is a constant tension in these meetings between APA's obligations under the OMA and making sure APA can deliver the required service on the one hand and Envestra's budgeting requirements and constant pressure to drive down costs on the other hand.*"[59]

In response to the queries Envestra raises APA provides further information as to costs and risks. There is a constant daily dialogue over a two to three week period in late April and early May between the Envestra and APA managers as they seek to resolve issues with the budget. Upon conclusion of this consultation process a revised budget is submitted to Envestra and a meeting of senior executives occurs in or around mid May to finalise the budget. The budget is then submitted to Envestra's Board for approval in June.

5.5.3 Monthly Reporting and Monitoring

Within 10 days of each month ending, APA reports to Envestra on all of the budgeted activities under the OMA, with a focus on comparing actual performance against budget performance.[60] The monthly reports are very detailed, usually comprising around 70 pages of analysis. They report on specific categories of capital and operational projects (such as minor capital works projects and customer connections) and report separately on major projects, revenue and haulage volumes.

Around one week after the submission of the monthly report APA and Envestra representatives (including those senior executives involved in setting the budget) meet to discuss the report. At these meetings Envestra questions any variance from budget, and where APA is over budget, the actions it will take to bring itself back within budget. Envestra also questions APA as to network performance, compliance with regulatory obligations and progress in achieving new customer connections.

Mr Ferguson's affidavit also deals with the process for adjustments to the budget during a year.[61] While the 2007 OMA allows a 2% variance from budget, any variances are identified and, if approved, adopted at monthly meetings. APA is bound by the budget adopted by Envestra's Board, and, as such, needs to have any variances from budget adopted by Envestra so that APA can continue to operate within the 2% variance allowed for by the 2007 OMA.

59 Affidavit of John Ferguson, paragraph 22.
60 Affidavit of John Ferguson, paragraph 30.
61 Affidavit of John Ferguson, paragraphs 34-35.

In respect of the budgeting and cost monitoring process, Mr Ferguson concludes:

> "*The budgeting and cost monitoring and control process under the OMA described in this affidavit is a rigorous and often abrasive process with Envestra relentlessly pursuing the driving down of costs and increased efficiencies. The robustness of the relationship under the OMA is illustrated by the fact that in its results for the half year ended 31 December 2009 a dispute for additional overhead costs totalling $2.2 million was noted. Now produced and shown to me and marked with the letters "JLF-2" is a true copy of an extract from Envestra's 31 December 2009 half yearly results recording the dispute under the OMA with APA. This dispute was subsequently resolved resulting in a small additional expense for prior and current year costs that was included in the 30 June 2010 financial results.*"[62]

5.5.4 Payment Provisions of the 2007 OMA

The remuneration payable to APA under the 2007 OMA in return for the provision of services outlined earlier in this section was structured so as to provide incentives to the APA Group to reduce Envestra's operating costs and promote increased network utilisation.

Under the 2007 OMA Envestra pays, subject to the budgeting parameters, all costs and disbursements reasonably incurred or outlaid by APA in the performance of its obligations. The structure of the payment provisions of the 2007 OMA, including the cost pass through nature of the contract, removes the incentive for APA to:

- artificially reduce expenditure to maximise its earnings (which is a risk with a fixed price contract); and
- artificially increase expenditure to maximise its earnings (which is a risk with a cost plus contact).

Furthermore, the transparency of costs incurred under the 2007 OMA enables Envestra to determine whether costs have been reasonably incurred (as required by the payment provisions of the OMA). If there is a dispute as to whether a cost has been reasonably incurred, clause 22 of the 2007 OMA enables Envestra to refer the dispute to independent expert dispute resolution.

The cost pass-through provisions under the 2007 OMA, and Envestra's continual scrutiny of the costs it is charged, ensures that Envestra automatically benefits from the economies of scale, scope and know-how available to the APA Group. That is, all cost efficiencies are immediately passed through to Envestra with the exception of the one-third cost reductions APA is permitted to retain via the incentive payments for one year before also being passed through to Envestra.

As previously stated, a primary basis for the payment of the NMF is to enable Envestra to access economies of scope, scale and know-how within the larger APA Group. The NMF is also set so as to incentivise APA to promote network growth. As explained in paragraph 28 of Peter Cain's affidavit:

62 Affidavit of John Ferguson, paragraph 40.

"The network management fee is deliberately struck by reference to revenue and not to a percentage of costs. In my experience an arrangement which is calculated as a percentage of total network revenue is more effective than a "costs-plus" approach because a "costs-plus" approach does not provide any incentive for the contractor to reduce its costs, in fact the incentive is to incur greater costs. This is because a "cost-plus" approach is often structured as a percentage of costs. Therefore, if costs are higher, the operator receives a percentage of a higher number. In my experience another example of remuneration of operators is a fixed fee. In the absence of other incentive mechanisms, such an arrangement does not provide a mechanism for any reduction in costs to flow back to Envestra or an incentive to grow the business."

Mr Cain's affidavit[63] also explains that the NMF represents payment to APA for three matters:[64]

reimbursement of certain costs of APA not recovered through the cost reimbursement provisions – for example costs of general management oversight of the agreement;

(a) the margin payable to APA for operating the network. As noted by Mr Cain:

"Any appointed operator would require a margin over efficient costs for the provision of its services. In negotiating the Victorian O&M Agreement, Envestra recognised that businesses operate with the purpose of making a profit and so an appropriate fee was required to be included in the Victorian O&M Agreement."; and

(b) an incentive to operate the network in a way which would increase Envestra's revenue; for example by expanding the networks.

This explanation also applies to the NMF payable under the 2007 OMA.[65]

Mr Ferguson describes the NMF payable under the 2007 OMA as follows:

"The NMF represents to APA in part the recovery of costs not passed through and not able to be passed through to Envestra, such as some corporate and executive costs, and a margin being the return to APA on its physical and intangible capital employed managing and operating the Envestra network under the OMA."[66]

He also states:

"The NMF also represents an incentive to APA to grow Envestra's business thereby increasing revenue and increasing the return to APA under the OMA."[67]

The purpose of making the incentive payments is to drive APA to achieve lower costs (which lower costs ultimately benefit consumers).

63 Affidavit of Peter Cain, paragraphs 25-27.
64 Mr Cain's comments were made in the context of the 1999 OMA but are equally applicable to the 2007 OMA given it employs the same remuneration structure.
65 Affidavit of Ian Little, paragraph 122.
66 Affidavit of John Ferguson, paragraph 66.
67 Affidavit of John Ferguson, paragraph 67.

The connection cost incentive payment is payable where the average capital cost of connecting new customer sites to the networks in a financial year is less than the average capital cost of connecting new customer sites to the networks in the prior financial year. The payment is equal to one third of the reduced average cost multiplied by the number of new customer site connections (with the sites weighted to reflect domestic, commercial and industrial connection costs).

The controllable cost per gigajoule incentive payment is payable where operating costs per gigajoule in a financial year are less than the costs for the preceding year. In such a case the payment is equal to one third of the reduction in those costs multiplied by the total amount of gas delivered for that financial year to customers whose consumption in that year was less than 10TJ.

As Mr Ferguson states, the incentive payments are a very significant driver of the relationship between Envestra and APA. The connection cost incentive payment drives down the cost of connection and the opex incentive payment drives down the operating costs per gigajoule of gas distributed.

Mr Ferguson's affidavit sets out the incentives paid by Envestra over the period 2001/2002 to 2010/2011. During those periods a controllable cost per gigajoule incentive payment was received in 9 out of the 10 years. A connection cost incentive payment was received in 6 out of the 10 years.
In his conclusion in respect of the incentive payments Mr Ferguson states:

> *"The incentives under the OMA represent the only way in which APA can obtain a better return under the OMA other than by growing the business and increasing revenue. APA only receives the benefit of the capex and opex incentives in respect of the year they were achieved. The benefit of those lower costs is ultimately passed on to the consumers."*[68]

As Envestra reimburses APA its reasonable costs, two-thirds of the benefit of lower costs relating to the matters represented by the incentive payments are immediately passed through to Envestra. APA retains the benefit of the remaining one-third of the lower costs for one year and then these lower costs are also passed through to Envestra. Consumers benefit from these lower costs because the costs achieved by Envestra in a regulatory period form the basis for determining Envestra's allowable costs for the next regulatory period.

The passing through of the cost benefits under the OMA was highlighted by the Tribunal in its recent decision allowing the NMF as allowable operating expenditure in South Australia:

> *"…the benefits of the NMF are already passed through to consumers. Because the payment of the NMF allows the management of Envestra's network to be done more efficiently, that is at a cost lower than if Envestra managed it in house, the total operating expenditure of Envestra is lower. It is this operating expenditure that forms the basis of Envestra's regulatory allowance."*[69]

[68] Affidavit of John Ferguson, paragraph 71.
[69] *Application by Envestra Ltd (No 2)* [2012] ACompT 3 at paragraph 265.

5.6 The Rationale for Outsourcing

As set out in the affidavits of Mr Little and Mr Cain, the commercial rationale for Envestra's outsourcing structure is to enable Envestra to seek to achieve lowest sustainable costs by accessing the economies of scale, scope and know-how of a significantly larger organisation. At paragraph 26 of his affidavit Mr Little states:

> *"The 1997 OMA (and its replacement the 2007 OMA) continues to deliver value to Envestra as an effective, prudent and efficient outsourcing arrangement. This conclusion is reinforced by the various benchmarking evidence that I have reviewed over the period of the outsourcing. The 1997 OMA was specifically put in place in the context of a regulatory regime requiring the network owner (and therefore operator) to operate its network with a view to incurring the lowest sustainable cost to consumers. Envestra considered that an outsource arrangement would deliver the lowest sustainable cost and reflect the performance of a prudent operator which was also a requirement of the Gas Access Code. The same requirement now applies under the National Gas Rules. In any event, there were no other service providers in 1997 who could offer Envestra the experience or economies of scale, scope and size of Boral."*

The affidavit of John Ferguson provides several practical examples of the efficiencies Envestra derives through the 2007 OMA:

(a) APA is able to use the combined projects of the APA Group and Envestra to purchase pipe in bulk and at lower prices than if the pipe were individually purchased by the APA Group and Envestra;

(b) by combining the APA Group's and Envestra's intelligent pigging schedule, savings on the cost of shipping pigging tools to Australia are able to be achieved (i.e. because the pigging tools are only required to be shipped once rather than on two separate occasions);

(c) the standards for design, construction, operation and maintenance for transmission and distribution pipelines are the same (given both types of pipeline need to comply with AS 2885) and so Envestra benefits from the costs of such activities being spread over a broader range of pipeline projects;

(d) Envestra is also able to benefit from the allocation of costs of easement management and pipeline surveillance activities over a greater range of such activities;

(e) by bulk purchasing metering equipment, meter control equipment and fittings and bulk purchasing plant and labour required for activities such as traffic control, concrete cutting, under-road boring and excavation, APA is able to achieve savings which could not be achieved if APA and Envestra individually purchased such items;

(f) by obtaining goods from suppliers and services from subcontractors jointly for Envestra and the remainder of the APA Group, such suppliers and subcontractors are able to offer lower prices:

    (i) because they avoid the cost of needing to tender twice;

    (ii) as they will, if successful, have greater volumes and certainty of supply.

5.7 Expert Analytical Evidence

In the previous sections of this submission Envestra has explained the logic for its decision to enter into the 1999 OMA and the 2007 OMA, which was to seek to achieve the lowest sustainable costs by accessing the economies of scale, scope and the know-how of a significantly larger organisation. The price payable to access these benefits is the NMF and the incentive payments.

This section outlines the independent expert evidence obtained by Envestra. That evidence demonstrates that since 2007 the OMA has achieved its intent of allowing Envestra to operate as an efficient operator and that the price payable under that outsourcing structure is consistent with industry standards. This evidence comprises:

(a) an expert report of Dr Hird's which explains that the payment of margins to access intangibles is common place in workably competitive markets and such margins continue in the long term (see attachment 5.4);

(b) an expert report of Katherine Lowe of NERA Economic Consulting which demonstrates that the NMF together with the incentive payments is comparable with margins earned by providers of comparable infrastructure operation and maintenance services (see attachment 5.5);

(c) an expert report of Dr Denis Lawrence of Economic Insights, which measures the productivity of Envestra's Victorian network relative to other networks. The conclusion of this report is that Envestra's productivity level is at the top of the range of productivity achieved by distribution businesses and is consistent with Envestra being an efficient cost performer (see attachment 3.1); and

(d) an expert report of Dr Denis Lawrence of Economic Insights, which benchmarks Envestra's cost performance against that of other distributors and demonstrates that Envestra's cost outcomes are efficient. The costs of Envestra which are used as the basis to conduct the analysis include the NMF and the incentive payments (see attachment 5.6).

In short, the above evidence demonstrates that:

- Envestra achieves cost efficiencies and productivity performance that is consistent with industry standards and good industry practice through its outsourcing structure; and
- the price Envestra pays to access these efficiency benefits of outsourcing (being the NMF and the incentive payments) is in line with margins earned by comparable service providers.

This evidence is discussed in the remainder of this section.

5.7.1 Economic Rationale for Margins

In the 2011 SA GAAR, Envestra engaged Dr Tom Hird of Competition Economists Group to provide an expert report that explains the existence of margins in competitive markets, the characteristics of margins and the period for which margins may be maintained. The analysis in that report is relevant to the current Victorian and Albury reviews.

Dr Hird observes that outsourcing of asset management and maintenance operations is commonplace in the economy, particularly in asset intensive businesses. This fact is also demonstrated by the NERA Margin Benchmarking Report (see section 5.7.2), given that report considers the margins of contractors who provide comparable services to those provided by APA. As Dr Hird observes:

> *"In order to take on such contracts businesses must expect to earn a profit margin even though they generally bring little or no physical capital to the contract."*[70]

Consistent with this, Dr Hird observes that material margins are paid for contracts in workably competitive markets, which margins are above those explained purely by a return on physical assets. These margins provide a return on intangible assets – that is, matters which enable a firm to lower costs. Such matters are economies of scale and scope and business "know-how" (expertise).

"Know-how" is everything from an effective organisational culture and management team to specific business processes and expertise.[71]

Economies of scale and scope are factors that enable the lowering of costs by spreading fixed/common costs across a larger number of operations or by allowing greater operational efficiencies. Economies of scale are the cost savings through performing more of the same activity. Economies of scope are the cost savings through performing multiple complementary activities. In the context of Envestra and APA, the economies of scale and scope operate as follows:

> *"For example, Envestra contracts with APA to operate and maintain gas pipelines around Australia. If operating and maintaining different gas pipelines are 'the same' activity then the advantages of doing so are economies of scale. If they are different activities then the advantages are economies of scope. APA also manages other infrastructure assets such as the electricity interconnector Murraylink which operates between SA and Victoria. Any advantages associated with managing Envestra's network and Murraylink would likely fall into the category of an economy of scope."*[72]

Intangible assets represented by know-how are costly to develop and/or difficult to replicate. Consequently, the margins on such intangible assets will not be bid down to zero.[73] Margins on intangible assets may therefore continue to exist in perpetuity. Dr Hird states:

> *"Contrary to statements by the AER, there is nothing inconsistent with earning a margin in perpetuity in workably competitive markets. It is costly/difficult to acquire intangible assets that allow one to lower costs. Unlike physical capital, intangible assets do not, in general, depreciate over-time. Knowledge or access to economies of scale/scope is, once obtained, not lost simply through the passage of time. As a consequence, those assets will, other things equal, earn a return in perpetuity. That is, the margin will not be competed away because it reflects a return on real investments/scarce resources – which competitors will only incur if they also expect to earn a margin."*[74]

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70 Hird Report, paragraph 19.
71 Hird Report, paragraph 23.
72 Hird Report, paragraph 27.
73 Hird Report, paragraph 29.
74 Hird Report, paragraph 30.

The importance of intangibles to economies is demonstrated by the view of Leonard Nakamura of the US Federal Reserve Bank that annual investment in intangibles in the United States is over one trillion dollars. Baruch Levy, also of the US Federal Reserve Bank, has concluded that an amount equal to between one-half and two-thirds of value of S&P 500 companies is represented by the value of intangible assets.[75]

In summary, intangible assets are assets of material value and infrastructure asset owners (such as Envestra) will be prepared to pay margins to access the benefits of intangible assets held by infrastructure asset service providers.

This is not the sole reason margins are paid in competitive markets. As set out in the NERA Benchmarking Report margins may also be paid:

(a) as a return on and return of capital required for physical assets;

(b) as recovery of a share of a contractor's common costs; and

(c) as compensation for asymmetric risks.[76]

However it is apparent that access to intangible assets is a major reason why market participants agree to pay margins.

5.7.2 NERA Benchmarking Report

Envestra engaged Ms Katherine Lowe of NERA Economic Consulting to prepare an expert report comparing the NMF together with the incentive payments with margins earned by providers of comparable infrastructure operation and management services (NERA Benchmarking Report). The purpose of the analysis was to assess whether Envestra was paying APA a margin consistent with margins earned by contractors providing comparable services to those provided by APA.

To undertake her analysis, Ms Lowe firstly identified service providers who provide comparable services to those provided by APA. Ms Lowe excluded from the sample entities that were more capital intensive than APA (and OEAM). This is because, all else being equal, the higher the capital intensity of a contractor the higher the margin it will require to recover the costs of that physical capital.

Table 3.1 of Ms Lowe's report, which is reproduced below, shows the sample used to undertake her analysis. Ms Lowe has undertaken a separate examination of the margins earned by:

- contractors providing infrastructure based contract services, irrespective of the type of infrastructure (referred to as the "All Infrastructure" sample set); and

- contractors providing services to network infrastructure assets, i.e. gas pipelines, electricity networks, water distribution, rail networks and telecommunication networks (referred to as the "Network Infrastructure" sub-set).

[75] Hird Report, paragraphs 36 and 37.
[76] NERA Benchmarking Report, paragraph 3.3.

The margins earned by the entities in the sample were then measured by use of the earnings before interest and tax margin (EBIT margin). Using the EBIT margin enables costs, income and margins to be considered in a standardised manner across all entities included in the sample.[77] The EBIT margin is determined by the formula: EBIT/revenue.

EBIT measures the difference between revenue and operating expenses (which expenses include directly incurred expenses, depreciation, amortisation and common costs). EBIT measures the funds available to the contractor to pay taxes and pay a return on physical and intangible assets.[78] That is, it measures the amounts received by a contractor in excess of the funds required to be earned to recover its costs.

Ms Lowe excluded from the calculation of the EBIT margins dividend and interest based income and profit generated by associates of the contractor unrelated to the provision of contractor services. The data used to calculate the EBIT and EBIT margins was obtained from company annual reports, for those entities listed on the ASX, and from accounts lodged with the Australian Securities and Investment Commission (Form 388 filings) for entities that were not listed.

77 NERA Benchmarking Report, paragraph 3.12.
78 NERA Benchmarking Report, paragraph 3.10.

Table 5.3: Final Sample of Comparable Service Providers

Sample Set		Company	Business Unit	Infrastructure Assets Serviced
All Infrastructure Sample Set	Network Infrastructure Sub-set	Downer EDI	Infrastructure	Energy, water, wastewater and transport sectors
		Tenix Alliance		Energy, water, wastewater, telecommunications and transport sectors
		United Group	Infrastructure	Energy, water, wastewater and transport sectors
		Worley Parsons	Infrastructure	Energy, water, wastewater and transport sectors
			Power	Energy sector
		Ausenco		Energy, environmental, mining and mineral processing sectors
		Bechtel		Energy, transport, mining, telecommunications, oil and gas sectors
		Clough		Energy, minerals and water sectors
		Downer EDI	Engineering	Energy, telecommunications and process engineering sectors
			Rail	Above rail sector.
		Fluor		Energy, mining and transport sectors.
		Hatch		Mining, metallurgical, manufacturing, energy and infrastructure sectors
		KBR		Energy, transport, water, wastewater, property and mining sectors
		Lend Lease	Project Management & Construction	Transport, residential, non-residential, communications, education, defence and pharmaceutical sectors
		SKM		Energy, resources, transport, defence, property and water sectors
		SMEC		Energy, transport, mining, urban development and water sectors
		Thomas & Coffey		Energy, mining, manufacturing, health care, defence and property services sectors
		Transfield Services		Energy, water, transport, telecommunications, facilities management, defence and complex process sectors
		United Group	Rail	Above rail sector
			Resources	Oil, gas, petrochemicals, chemicals and minerals industries
		Worley Parsons	Hydrocarbons	Oil, gas, refining and petrochemical industries
			Minerals and Metals	Minerals and metals industries

To determine the implied EBIT margin under the 2007 OMA it was necessary to divide the sum of the NMF and the incentive payments by the payments made by Envestra under the 2007 OMA in reimbursement of APA's reasonable costs. The implied EBIT margin and the margins earned across the All Infrastructure sample of comparable service providers over the past 10 and 5 years is shown in table 4.3 of Ms Lowe's report and re-produced below.

Table 5.4: Confidence Interval for All Infrastructure Population Mean

Parameter	2002-2011	2007-2011
Sample mean	5.6%	6.3%
Sample standard deviation	5.4%	4.8%
Number of observations in sample (n)	190	104
95% confidence interval for population mean*	**4.8%-6.4%**	**5.4%-7.2%**
OMA Implied EBIT Margin	**6.4%**	**6.1%**

* $\beta_{est} \pm t_{\frac{\alpha}{2}} se(\beta_{est}) = \beta_{est} \pm t_{\frac{\alpha}{2}} \frac{s}{\sqrt{n}}$

Ms Lowe's analysis shows:

(a) over the period 2002-2011 the mean EBIT margin of the All Infrastructure sample of comparable contractors was 5.6% while the 95% confidence interval surrounding this estimate ranged from 4.8% to 6.4%. The mean implied EBIT margin across the OMAs was 6.4%, which was at the upper bound of the 95% confidence interval;

(b) over the period 2007-2011, which period corresponds with APA operatorship, the mean EBIT margin of the All Infrastructure sample of comparable contractors was 6.3% while the 95% confidence interval for the true mean ranged from 5.4% to 7.2%. Over this period the mean implied EBIT margin paid by Envestra was 6.1%, which was 0.2% lower than the sample average and toward the middle of the 95% confidence interval.

Ms Lowe also compares the implied EBIT margin and the margins earned across the Network Infrastructure sub-set of comparable service providers. This analysis shows that over the periods 2002-2011 and 2007-2011 the implied EBIT margin paid by Envestra was 0.3 per cent lower than the Network Infrastructure sample mean in both periods (6.4 per cent versus 6.7 per cent and 6.1 per cent versus 6.4 per cent respectively).

Ms Lowe concludes that the NMF together with the incentive payments paid by Envestra to APA is in line with the margins received by other comparable contract service providers that supply asset management services to third parties.

5.7.2.1 AER's Critique of Previous Benchmarking Reports

In the 2011 South Australian GAAR Final Decision, the AER stated that the NERA Benchmarking Report was not comparing margins on a like for like basis. This was because, in the AER's view, NERA described the EBIT margin as providing a measure of funds available to the contractor to pay taxes and pay a return on physical and intangible assets.[79]

Ms Lowe explains in her report that the sample firms are of low capital intensity and therefore the margins those firms are receiving are principally for accessing intangible assets. The contractors in the sample for the South Australian GAAR had levels of physical capital at or below those used by APA. Tax is levied on all margins, including that under the OMAs. Therefore the NERA Benchmarking Report is comparing like with like – it is comparing margins available to provide a return on intangible assets and pay tax.[80]

79 Final Decision, page 242.
80 NERA Benchmarking Report, paragraph 5.5.

The second concern identified by the AER was the volatility of the margins in the NERA sample. As Ms Lowe explains in her report, this volatility reflects the fact that the total EBIT margin of an entity will change as it enters into new contracts, as existing contracts cease and as, where it has entered into fixed price contracts, its costs change. As the EBIT margins reflect the performance of an overall business they would be expected to vary from year to year.

It is also of significance to note:

(a) the NERA benchmarking methodology was first applied by NERA in the 2008 Victorian GAAR. That methodology was subject to extensive review by the Allen Consulting Group, an expert retained by the ESCV. The Allen Consulting Group agreed that the EBIT margin metric was the most appropriate measure of a margin, agreed with the approach adopted by NERA in identifying comparable service providers and agreed with the cut-off point applied by NERA to exclude from the sample entities with a capital intensity over that of OEAM;[81] and

(b) in the recent South Australian GAAR, Wilson Cook, the expert engaged by the AER, found the NERA benchmarking report from that review was "*a well researched and convincing study that concluded that the revenue asset management charge levied on Envestra by the APA Group resulted in a gross margin not out of line with those earned by comparable, mainly asset management, businesses.*"[82]

That is, two experts retained by regulators have accepted the methodology underpinning NERA's analysis.

Furthermore, the Tribunal accepted the conclusions of the NERA Benchmarking Study in the South Australian GAAR. The Tribunal stated: "*It is apparent, at least on the balance of probabilities, that the costs incurred by APA in managing Envestra's networks, including the NMF, are within industry standards and that APA is not earning an abnormally large margin on its operations*."[83]

5.7.3 Productivity Analysis

The Victorian gas distributors have engaged Dr Denis Lawrence to undertake an analysis of the productivity performance of the Victorian gas distributors. This analysis is set out in the report "The Total Factor Productivity Performance of Victoria's Gas Distribution Industry" (Economic Insights Productivity Report). The report looks at the following three key measures of productivity:

- *Total Factor Productivity (TFP)* – which measures the rate of change in the ratio of total output relative to *all* inputs used;
- *Partial Factor Productivity (PFP)* – which measures the rate of change in the ratio of one or more outputs relative to *one* particular input (such as operating or capital expenditure); and
- *Multilateral TFP (MTFP)* – which measures the absolute (or overall) productivity levels of different businesses.

81 Allen Consulting Group, Benchmarking of Contractors' Margins – Review of NERA and PricewaterhouseCoopers Reports – Report to the Essential Services Commission of Victoria, pages 4-9.
82 Wilson Cook & Co, *Review of Expenditure of Queensland & South Australian Gas Distributors: Envestra Ltd (South Australia*), page 47.
83 *Application by Envestra Ltd (No 2)* [2012] ACompT 3 at paragraph [252].

The TFP and MTFP measures provide a comprehensive view of overall economic performance. This is because these measures take into account all the factors that influence productivity performance. Dr Lawrence has measured TFP across three outputs (throughput, customer numbers and system capacity) and 8 inputs (opex, length of transmission pipelines, high pressure pipelines, medium pressure pipelines, low pressure pipelines and services, meters and other capital).

The analysis compares the productivity performance of the three Victorian gas distributors with Jemena's New South Wales gas distribution business (JGN) and Envestra's Queensland and South Australian gas distribution businesses. The comparative analysis has been undertaken for the 1999 to 2009 period, which reflects the period for which data were available for all five businesses included in the sample.

Dr Lawrence has been required to "normalise" the data to ensure comparability between the five distributors included in the sample. The primary adjustment made was to remove transmission mains from the data. This is because both Envestra and JGN have relatively high amounts of transmission mains given that the geographic area served by both networks is large. Government levies and unaccounted for gas has also been excluded to ensure comparability.

The results of the productivity analysis over the 1999 to 2009 period provide compelling support for Envestra's outsourcing structure.

In regard to TFP, Dr Lawrence found that Envestra's Victorian network had the fastest rate of TFP growth over the 1999 to 2009 period:

> *"Comparing the three Victorian GDBs', JGN's and Envestra SA's TFP indexes, Envestra Victoria and SP Ausnet has the highest TFP growth for the period up to 2009 (the latest year for which data are available for all the included GDBs) with average annual growth rates of 2.4 per cent and 2.3 per cent, respectively. They were followed by JGN and Multinet with average annual TFP growth rates of 1.9 per cent and 1.8 per cent, respectively. The smaller Envestra SA had the lowest TFP growth rate at a still very reasonable 1.4 per cent."*[84]

Most importantly, Dr Lawrence's analysis showed that Envestra has considerably higher overall productivity levels than all of the distributors included in the sample. Specifically, Dr Lawrence found Envestra Victoria's MTFP to be around 13% higher than SP Ausnet, Multinet and JGN (those networks in the sample not owned by Envestra). Specifically, Dr Lawrence noted that:

> *"The MTFP results indicate that the three Victorian GDBs had the highest overall productivity levels in 2009, the latest year for which data are available for all the included GDBs. When transmission-equivalent inputs are excluded, Envestra Victoria has had the highest TFP level of the five included GDBs by a 12.6 per cent margin in 2009. It also had the highest TFP level for all of the 13 year period. In 2009 Multinet and SP AusNet were second and third placed and were followed closely by the much larger JGN. By 2011 SP AusNet's TFP level had moved ahead of Multinet's by 4 per cent. Envestra SA achieved good productivity levels in 2009 despite having the lowest overall energy density and a domestic energy density that is comparable to JGN's but less than 40 per cent those of the three Victorian GDBs."*[85]

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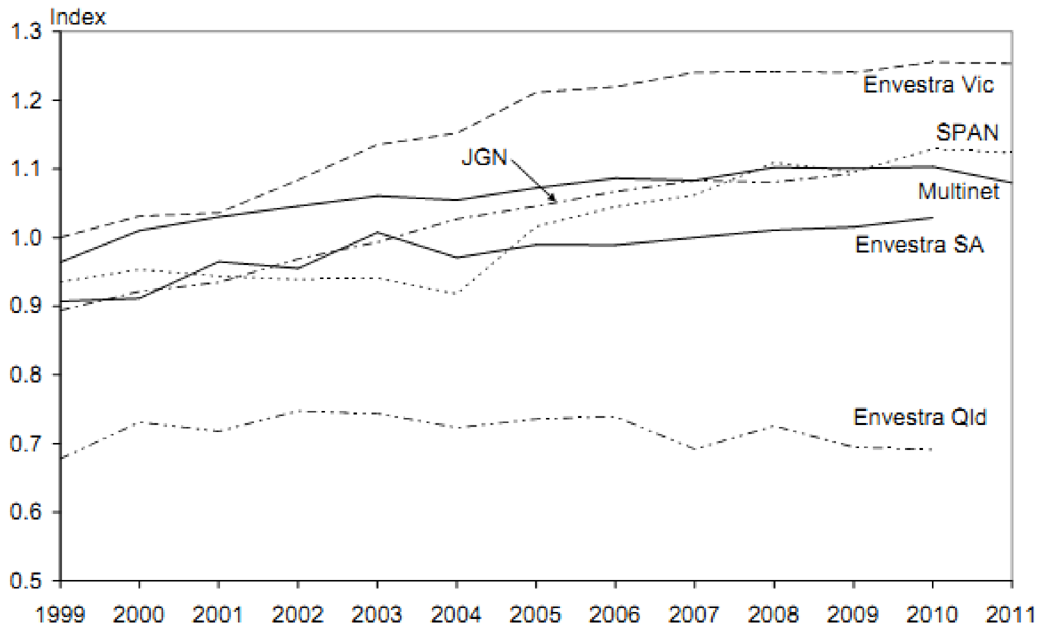
84 Economic Insights Productivity Report, page 49.
85 Economic Insights Productivity Report, pages 44-45.

The MTFP results are shown in figure 5.1, which figure is taken from figure 6.2 in the Economic Insights Productivity Report (pg. 44).

Figure 5.1: Australian GDB multilateral TFP indexes, 1999-2011



Through its outsourcing structure, Envestra achieves efficient actual cost performance that is consistent with/exceeds good industry practice/industry standards and the requirements of the National Gas Rules.

5.7.4 Cost Benchmarking Report

The Victorian gas distributors also engaged Dr Denis Lawrence to undertake an analysis of the cost performance of the Victorian gas distributors over the period 1999 to 2010. This analysis is set out in the report "Benchmarking the Victorian Gas Distribution Businesses' Operating and Capital Costs using Partial Productivity Indicators" (Economic Insights Cost Efficiency Report).

The report compared the performance of the Victorian gas distributors against 8 other Australian gas distribution businesses and 3 New Zealand gas distribution businesses using public domain data. The report analyses a range of partial productivity indicators, including opex per customer, opex per kilometre, opex per unit of output, capex per customer, capex per kilometre and capex per unit of output.

Dr Lawrence found Envestra performed better than the sample average across most of the partial productivity indicators. The report concluded:

> "*Based on these indicators and recognising the nature of their networks, the Victorian GDBs have performed well on most indicators. Opex efficiency has been particularly strong, considering that the Victorian GDBs have older systems and higher proportions of cast iron and other low pressure mains.*

Some of the indicator growth rates observed in the first half of the periods in the immediate aftermath of reform and ownership changes have slowed in the second half of the period as cost reductions become progressively harder to achieve after these initial gains are made. Further growth rates of key indicators are more likely to reflect, at best, the generally lower average growth rates of the more recent period due to this 'convergence' effect."[86]

Envestra notes that Dr Lawrence did not adjust the data in this report to remove Envestra's relatively high levels of transmission mains.

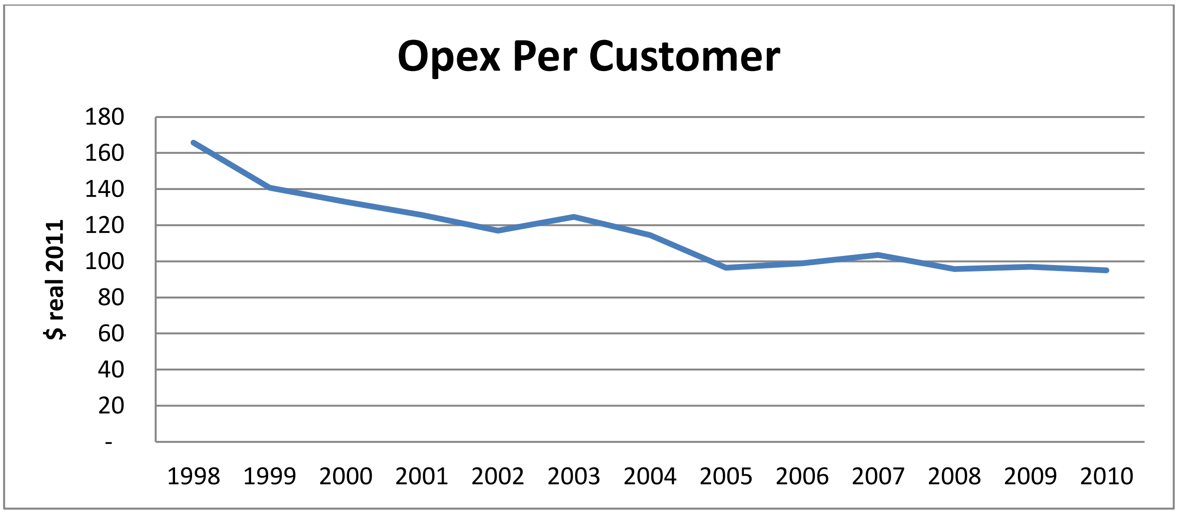
In short, taking all of its costs into account, including the NMF, incentive payments and transmission mains, Envestra is an efficient cost performer. There is certainly no evidence that outsourcing by Envestra has resulted in inefficient costs.

5.8 Operating Cost per Customer

The Victorian network was operated on an in-house basis prior to its purchase by Envestra in 1999. Since that time, Envestra has delivered a reduction in operating expenditure (opex) per customer of 43%. This reflects a considerable reduction in actual operating expenditure and has been made despite a 36% growth in customer numbers over this period.

This cost outcome is driven by Envestra's outsourcing structure and corroborates the findings of Dr Lawrence that Envestra incurs efficient costs.

Figure 5.2: Operating Cost Per Customer in Victoria, 2011 to 1998



5.9 Prior Regulatory Decisions

Envestra's outsourcing arrangement has been thoroughly reviewed by the AER, its predecessor in Victoria (the ESCV) and various review bodies over the past 10 years. In total, Envestra's outsourcing arrangement has been subject to 10 regulatory review processes and in all but one of those reviews the NMF was found to represent efficient costs.

86 Economic Insights Cost Efficiency Report, page ii.

The regulatory review in which the NMF was found not to be recoverable was the 2006 South Australian GAAR, in which ESCOSA rejected the NMF relying on similar arguments to those relied upon by the AER in the 2011 South Australian GAAR. In 2008 and 2012 the ESC Appeal Panel and the Australian Competition Tribunal respectively concluded that the NMF was an efficient cost. As noted by the Tribunal in its 2012 decision, Envestra's appeal against ESCOSA's 2006 decision was dismissed on procedural grounds only.[87]

An outline of the decisions from the past 10 regulatory reviews is summarised in table 5.6. This section discusses in more detail the two most recent regulatory reviews of the outsourcing arrangement, which were conducted in respect of the South Australian and Victorian networks.

Table 5.6: Outcomes of Regulatory Reviews into Envestra Outsourcing Arrangement

No.	Year	Regulator	NMF Accepted
1	2001	Queensland Competition Authority	Yes
2	2001	South Australian Independent Pricing and Access Regulator (SAIPAR)	Yes
3	2002	Essential Services Commission of Victoria – Victorian Network	Yes
4	2002	Essential Services Commission of Victoria – Albury Network	Yes
5	2006	Queensland Competition Authority	Yes
6	2006	Essential Services Commission of South Australia	No
7	2008	Essential Services Commission of Victoria – Victorian Network	Yes
8	2008	Essential Services Commission of Victoria – Albury Network	Yes
9	2011	Australian Energy Regulator – South Australia	Yes
10	2011	Australian Energy Regulator - Queensland	Yes

5.9.1 2011 South Australian Gas Access Arrangement Review

In the 2011 South Australian GAAR, Envestra submitted (as it does in this submission) that the relevant considerations in assessing an outsourcing arrangement are:

- whether the arrangement enables the service provider to achieve efficient cost outcomes; and
- whether the price (the margin) payable under the outsourcing arrangement to access those efficient cost outcomes is consistent with industry standards.

Also relevant is a consideration of circumstances surrounding the entry into the contract as these will indicate the outcomes management intended to achieve through the outsourcing and are therefore relevant to test whether the arrangement is one which would be entered into by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

[87] See *Application by Envestra Ltd (No 2)* [2012] ACompT 3 at paragraph 273. The South Australian Appeal Panel also noted this.

The AER did not accept Envestra's submission as to what was the appropriate test to apply under the NGR. It applied a framework under which it firstly assessed whether there was a potential incentive for a Service Provider to agree non-arm's length terms. If the potential for such an incentive existed (whether or not it was acted upon and whether or not there is any evidence the contract represents non-arms length terms) the AER only allows the recovery of certain types of costs under the outsourcing contract and not all costs under that contract. These costs are the contractor's direct costs and the following categories of costs:

(a) a reasonable allocation of the contractor's common costs;

(b) a return on and of physical assets used in the provision of services; and

(c) an allowance for any asymmetric risks arising under the contract.

As explained throughout this chapter, the NMF and the incentive payments are amounts payable to access efficient cost outcomes. They are payments to access APA's economies of scale, scope and know-how. They therefore did not fit within the above recoverable cost categories allowed for under the AER's framework.

Consistent with its view that the AER's framework represented an incorrect application of the NGL and NGR, Envestra appealed the decision to disallow recovery of the NMF to the Australian Competition Tribunal. The Tribunal found that:

(a) it was apparent from the evidence provided by Envestra that it is cheaper for Envestra to pay APA to manage its networks even taking into account the NMF than for Envestra to operate the networks itself;

(b) it was apparent that the costs incurred by APA in managing Envestra's networks, including the NMF, are within industry standards and that APA is not earning an abnormally large margin on its operations;

(c) APA may well not agree to manage Envestra's network without the payment of the NMF;

(d) the NMF was a payment required to access the management services of APA; and

(e) such a cost is clearly one that would be incurred by a prudent service provider, acting efficiently.

In the above circumstances it was inappropriate to maintain, as the AER sought to do, that the NMF does not comply with rule 91 of the NGRs (permitting recovery of efficient costs).

The Tribunal also found that the:

(a) NMF is not a one-off cost to improve the efficiency of the management of the network. It is a fee paid each year in order to have access to the efficiencies offered by APA; and

(b) benefits of the NMF are passed through to consumers as the cost efficiencies derived through the use of outsourcing are already reflected in Envestra's operating costs.

The Tribunal found that the AER fell into error when, despite these facts, it concluded that the NMF was not an efficient cost. The Tribunal also found that the AER's conclusion was therefore unreasonable.

The Tribunal also found that the AER's conclusion that the NMF was an efficiency incentive and that Envestra should retain the benefits of it for only six years misunderstood the role of the NMF and the effect it had on the cost base used to calculate Envestra's regulatory allowance.

The Tribunal therefore overturned the AER's decision on the basis that the NMF should have been classed as an item of efficient operating expenditure given it allows Envestra to achieve efficient cost outcomes that are consistent with industry standards.

5.9.2 2008 Victorian Gas Access Arrangement Review

The NMF and the incentive payments were considered by the ESCV in the 2008 GAAR. In that review, the ESCV found:

(a) the features of the 1999 OMA were consistent with the operator having an incentive to incur a prudent and efficient level of costs and "would appear generally prudent";

(b) the operator was entitled to be reimbursed only its actual costs in operating and managing the networks;

(c) the operator shares in superior performance against cost benchmarks under the contract, providing it with an incentive to incur an efficient level of cost;

(d) there is periodic review of the cost benchmarks; and

(e) the contract provides transparency of the operator's costs to Envestra.[88]

The ESCV accepted that Envestra was likely to gain from the economies of scale available to Origin and that the direct costs of OEAM would be lower than the costs that Envestra would be able to achieve had it performed the services in-house. However, the ESCV did not consider that Envestra had substantiated by how much its costs were reduced and therefore determined to allow recovery of only 50% of the NMF.[89]

Envestra appealed the ESCV's decision to the Essential Services Commission Appeal Panel, which panel allowed recovery of 100% of the NMF.[90] The Appeal Panel found that Envestra had produced sufficient evidence to demonstrate that the NMF was an efficient cost and to demonstrate that Envestra's management made an adequate assessment in 1999 of the appropriateness of the decision to outsource.

The Appeal Panel's 2008 decision and the Tribunal's 2012 decision are consistent and have resulted in the NMF being regarded as an efficient cost.

5.10 AER Framework

The AER in the 2011 South Australian GAAR applied a two stage framework to assess Envestra's outsourcing arrangement. Under this framework the AER first considered (in "Stage 1") whether a service provider had an incentive to agree to non-arm's length terms at the time of entering into the outsourcing contract.

88 ESCV, Gas Access Arrangement Review 2008-2012, Final Decision 7 March 2008, page 67.

89 ESCV, Gas Access Arrangement Review 2008-2012, Final Decision 7 March 2008, pages 90-92.

90 Essential Services Commission Appeal Panel, *Vic Gas Distribution Pty Ltd (Envestra) v Essential Services Commission* 11 November 2008.

If the contract passes Stage 1, then the costs of the outsourcing arrangement are subject to a limited review by the AER (for example, a review as to whether the costs incurred under the contract are required to provide reference services). If the contract fails Stage 1, then the AER undertakes an analysis pursuant to Stage 2B under which the AER only allows the recovery of certain types of costs incurred by the contractor.[91]

The Tribunal did not consider in any detail the appropriateness of Stage 1 of the AER framework (as it was not required to). However, the Tribunal agreed with Envestra's submissions that the application of Stage 2B had led the AER into error and the employment of that framework by the AER produced a result contrary to the NGL and NGR.

Envestra re-iterates its view that Stage 2B of the AER's framework does not comply with the NGL and NGR because the framework contains the following errors:

(a) the framework considers costs from the perspective of the contractor and not from the perspective of the service provider. The framework assumes that the service provider will incur the same costs as the contractor – that is, that the service provider is able to access the same economies of scale, scope and other efficiencies as its contractor and without incurring any costs to access such efficiencies;

(b) where a contract passes Stage 1 of the framework then the margin payment is recoverable. However, if a contract in identical form fails to pass Stage 1 of the framework then only certain types of costs that comprise the margin are recoverable. Therefore, there could be two identical contracts but the amounts recoverable under each contract would be different. This approach is illogical;

(c) the framework only allows margins paid on account of the benefits of accessing know-how, economies of scale and scope to be recovered for a limited period of 6 years, contrary to the evidence that in real world markets (that is, workably competitive markets) margins are paid to access these benefits for periods in excess of 6 years. As the Tribunal found, a conclusion that Envestra should only retain the benefits of the NMF for 6 years misunderstands the role of the NMF and the effect it has on the cost base used in the calculation of Envestra's regulatory allowance;

(d) at no point does the framework question whether the costs being paid under the relevant contract are costs that would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services. That is, the framework never addresses the test in rule 91;

(e) the framework fails to take account of the key reason why a service provider acting efficiently and prudently would outsource (which is to ensure better cost outcomes). There is nowhere in the framework allowing for recovery of a margin paid to achieve better cost or service outcomes and yet this is the fundamental reason why, in actual markets, margins are paid;

(f) the framework is constructed in such a way that where a contract does not pass the presumption threshold the full margin is unlikely ever to be recovered. This is because the reasons put forward by the AER for allowing a margin do not comprehensively cover the reasons that margins are paid in competitive markets. This is despite the fact that such components are included in any margin negotiated between arm's length parties;

91 These are the contractor's direct costs and the following "legitimate" costs, being a reasonable allocation of the contractor's common costs, a return on and of physical assets owned by the contractor and an allowance required to compensate the contractor for asymmetric risks.

(g) as shown by the NERA Benchmarking Report, the AER's Stage 2B allowable costs do not adequately explain margins observed in competitive markets. The NERA Benchmarking Report shows margins over total costs (including overheads) demonstrating that margins recover more than overhead amounts and common costs. The sample relates to firms with little or no physical assets, showing that return on physical assets does not explain the margins. Asymmetric risk will tend to be balanced out over a business's different contracts, meaning that the long term margins outlined in the NERA Benchmarking Report are not explained solely by reference to an assumption of asymmetric risk.[92]

5.10.1 The Correct Approach

The 1999 OMA and the 2007 OMA were both entered into by independent parties and in circumstances where Envestra had strong incentives to minimise its costs (and no countervailing incentive existed). The strong incentive to lower costs that existed at the time was accepted by the ESCV. The decision to enter into the outsourcing arrangement was considered prudent by both the ESCV and the Essential Services Commission Appeal Panel in 2008.

Further, the margins payable under the 1999 OMA have been found to be efficient by both the ESCV in 2002 and the Essential Services Commission Appeal Panel in 2008 (with the ESCV in 2008 allowing recovery of half of the fee). The equivalent margins across all of Envestra's other networks have also been held to be recoverable expenditure.

That is, there is no reason to consider, having regard to the circumstances of entry into the contracts, that the 1999 OMA and the 2007 OMA reflect uncommercial terms and the contracts, or contracts on equivalent terms, have already been subject to extensive regulatory review and approval. That background should inform the extent to which further consideration of the contracts is required.

The relevant test is whether the 2007 OMA enables Envestra to achieve efficient costs in the operation of its Victorian network and whether the margin payable under the 2007 OMA is in line with market rates.

These matters are established by the following evidence submitted by Envestra:

- Envestra had a strong incentive to enter into an efficient outsourcing arrangement (Cain and Little affidavits);
- Envestra is an efficient business (Economic Insights);
- outsourcing enables Envestra to achieve efficiencies it could not otherwise access (Little and Ferguson affidavits); and
- Envestra pays a margin comparable with market rates under its outsourcing arrangement (NERA).

92 Hird Report, paragraph 21.

5.11 Summary

Envestra's outsourcing arrangement has been subject to extensive regulatory scrutiny. It has been determined for the South Australian, Queensland, Victorian and Albury networks that the costs incurred under the outsourcing arrangements have satisfied the relevant criteria for approving operating and capital expenditure under the NGL and NGR (or under the predecessor legislation, which is stated in equivalent terms).

The evidence accompanying this AAI demonstrates that Envestra:

(1) was strongly incentivised to achieve efficient cost outcomes at the time it entered into the outsourcing arrangement in 1999 (as accepted by the ESCV and Essential Services Commission Appeal Panel);

(2) productivity levels and cost outcomes in Victoria are consistent with Envestra achieving efficient cost outcomes and complying with good industry practice and standards (as per management's intention at the time it entered into the outsourcing arrangement in 1999); and

(3) the payments made to enable Envestra to incur efficient operating costs, namely the NMF and incentive payments, are consistent with industry standards and achieve the lowest sustainable cost.

With regard to the first point, the ESCV and the Appeal Panel found that Envestra management made a prudent decision to enter into the outsourcing arrangement in 1999. The ESCV agreed and noted that, given the circumstances that prevailed in 1999, Envestra had a strong incentive to ensure that it chose the option that yielded the lowest sustainable costs. The Appeal Panel noted that *'the Applicant [Envestra] entered into the 1999 OMA with a view to achieving the lowest sustainable cost of providing services'*.[93]

With regard to the second point, the evidence demonstrates that management's intention back in 1999 of achieving efficient costs in the operation of its Victorian network has been vindicated by actual results. In particular, the Economic Insights Productivity Report demonstrates that Envestra has overall productivity levels of around 13% higher than SP Ausnet, Multinet and JGN (those networks in the sample not owned by Envestra). That is, Envestra has considerably higher productivity levels than its industry peers. Operating expenditure per customer has been driven down by 43% since 1998.

With regard to the third point, the NERA Benchmarking Report demonstrates that the fee Envestra pays to APA is consistent with margins paid to comparable service providers. Envestra is therefore paying a price to access the intangible assets of APA that is consistent with market prices and the price that would be paid by a prudent Service Provider acting efficiently to achieve the lowest sustainable cost of providing services.

Envestra submits that all of the evidence of its management and experts points to the conclusion that the NMF and the incentive payments are efficient costs, the payment of which achieves results beneficial to consumers and therefore are costs consistent with the NGL and NGR. Envestra relies on the whole of the evidence submitted to the AER to demonstrate that its outsourcing is efficient. Envestra has therefore included the NMF and incentive payments into its expenditure forecasts for the 2013 to 2017 Access Arrangement period (see chapters 6 and 7).

93 Paragraph 113.

6. Operating Expenditure

6.1 Introduction

This chapter sets out the forecast operating expenditure (opex) that is required by Envestra over the 2013 to 2017 Access Arrangement period to provide services in a manner that satisfies its obligations under the National Gas Rules (NGR). Importantly, the NGR require forecast opex to reflect that of a prudent service provider acting efficiently and consistent with good industry practice to achieve the lowest sustainable cost of delivering services.

Envestra has applied a “base year roll-forward” approach to forecast its opex requirements over the 2013 to 2017 Access Arrangement period. Under this approach, Envestra has adjusted actual opex incurred in 2011 for forecast changes in the cost of labour and materials and for costs that were not included in the base year (for example, costs arising from new obligations imposed on Envestra from 2011).

The above approach to forecasting opex has been commonly accepted by the AER and its predecessors. This is because, unlike capital expenditure, the majority of opex is recurrent in nature such that the types of costs incurred in the “base year” are likely to be representative of costs incurred going forward. It can also be inferred that base year costs are efficient given the significant commercial and regulatory incentives for Envestra to minimise costs.

This chapter sets out the relevant requirements of the NGR in relation to forecasting opex. This chapter then outlines the approach taken by Envestra to develop its forecast opex, including a discussion of the base year roll-forward approach, those activities that are not included in the base year and how those costs are adjusted over the regulatory period.

6.2 Requirements of the National Gas Rules

Rule 91 of the NGR sets the key criteria governing the recovery of opex. Rule 91 states:

> *“(1) Operating expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.*
>
> *(2) The AER's discretion under this rule is limited.”*

As set out in chapter 5, rule 91 does not require Envestra’s opex to be the lowest sustainable cost of delivering pipeline services. Rather, if a service provider has undertaken expenditure which is consistent with what would be undertaken by a prudent service provider acting efficiently to achieve lowest sustainable cost, then the expenditure is recoverable.

In addition, rule 74 of the NGR states that in relation to forecasts and estimates:

> *“(1) Information in the nature of a forecast or estimate must be supported by a statement of the basis of the forecast or estimate.*
>
> *(2) A forecast or estimate:*
>
> > *(a) Must be arrived at on a reasonable basis; and*
> >
> > *(b) Must represent the best forecast or estimate possible in the circumstances.”*

6.3 Forecasting Approach

Envestra has derived its forecast opex using the "base year roll-forward approach", where 2011 is used as the base year. This reflects the fact that the majority of opex is recurrent, such that costs incurred in 2011 will be reflective of costs that will also be incurred over the 2013 to 2017 Access Arrangement period. In addition, Envestra has undertaken separate forecasts for those costs that are not included in the base year.

The approach taken by Envestra to forecast opex is summarised in the following six steps:

(1) *Determine Base Year Opex* – take opex in the most recent year for which actual information is available as a prudent and efficient base for forecasting opex over the 2013 to 2017 Access Arrangement period, which in this case is opex incurred in 2011;

(2) *Adjust Base Year Opex* – adjust the 2011 base year opex for those costs where the base year roll-forward approach is not appropriate, which in this case includes certain payments made by Envestra to its contractor (see section 6.5.1) and network development costs (see section 6.5.2).

(3) *Determine 2012 Opex* - The adjusted 2011 base year opex is then adjusted for cost escalation to derive 2012 opex (see section 6.6);

(4) *Non Base Year Opex* – identify those items that are not in the base year but are forecast to be incurred over the 2013 to 2017 Access Arrangement period, which includes those costs removed in step 2 and other non base year opex, such as changes in opex that are required to meet new regulatory obligations (see section 6.7);

(5) *Growth Opex* – determine the incremental cost of supplying new customers that are forecast to be connected to the network over the 2013 to 2017 Access Arrangement period (see section 6.8); and

(6) *Apply Cost Escalation* – escalate forecast opex for expected changes in input cost (see section 6.9).

The remainder of this chapter explains in more detail the application of the above steps to forecast opex over the 2013 to 2017 Access Arrangement period.

In relation to unaccounted for gas (UAFG), Envestra has assumed that the current arrangements for UAFG will continue. That is, a benchmark level of UAFG will be determined whereby retailers are responsible for the cost of supplying gas for UAFG up to that benchmark, with Envestra bearing the cost of any gas required where the level of UAFG exceeds the benchmark.[94] Given this, there are no amounts included in the forecast opex benchmarks for UAFG.

[94] Attachment 6.2 sets out the proposed benchmark UAFG levels for the 2013 to 2017 Access Arrangement period, which are based on the actual level of UAFG for 2010 (this being the most recent reconciled UAFG data available).

6.4 Determine Base Year Opex

The opex incurred by Envestra in 2011 is used as the base year as this represents the most recent year for which actual information will be available prior to the start of the 2013 to 2017 Access Arrangement period.[95] The 2011 base year therefore incorporates the most recent information relating to the scope and cost of providing reference services over the next regulatory period.
Importantly, the significant commercial and regulatory incentives placed on Envestra ensure that 2011 opex reflects the efficient costs of providing reference services.

A key commercial driver for reducing expenditure is in the 2007 Operating and Management Agreement (2007 OMA) between Envestra and the APA Group[96]. The 2007 OMA contains an incentive for APA to achieve reductions, so that the operating cost per gigajoule are less than in the preceding year. John Ferguson, APA's General Manager Networks, notes in his affidavit that a significant incentive fee was paid to APA in respect of the 2011 base year, reflecting cost efficiencies achieved in that year. Mr Ferguson states that:

> *"The incentive mechanisms are a very significant driver of the relationship between Envestra and APA."*[97]

From a regulatory perspective, the incentive properties of the regime provide an economic benefit to Envestra from minimising expenditure.

Given these strong incentives, a high degree of confidence can be placed on 2011 opex reflecting efficient costs for the purpose of forecasting opex. The use of 2011 opex is also an integral part of our forecasting approach as expected changes in costs from this point are applied to the base year to forecast costs in each year of the 2013 to 2017 Access Arrangement period.

The use of the penultimate year of an access arrangement period to set the base year is also consistent with regulatory precedent. For example, the AER applied the penultimate year to set base year expenditure in its recent review into Envestra's South Australian and Queensland networks. The predecessor to the AER, the Essential Services Commission of Victoria, also applied this approach at the last review of the Network.

The 2011 base year opex is then broken down into various cost categories for the purpose of undertaking the base year roll-forward. These categories are consistent with that used in the Network regulatory accounts and are as follows:

- *Network Operating Costs* – which includes network planning, system design and the general state management and support for the network's operations;

- *Billing and Revenue Collection* – which includes activities associated with billing retailers and certain customers and the collection of revenue;

- *Network Development* – which includes the costs of processing gas connection orders and mains extension requests (including the costs of coordinating those capital works) and the marketing of gas aimed at increasing network connections and usage;

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95 As noted in chapter 3, Envestra has relied on a forecast of 2011 opex as actual information for the complete year is not yet available. It is intended to update the 2011 base year once the regulatory accounts are finalised at the end of April 2012.

96 As explained in chapter 5, Envestra outsources the operation and management of its Network to the APA Group.

97 Paragraph 67.

- *Regulatory Costs* – which include the costs of complying with regulatory obligations, including the payment of licence fees;

- *Other Operating Costs* – which includes various costs of an administrative/overhead nature, including training, information technology, accounting, human resources and insurance;

- *Distribution Pipelines* – which includes the general maintenance of the Network, including undertaking piecemeal replacement;

- *Cathodic Protection* – which involves the use of either impressed current or sacrificial anodes to prevent the corrosion of steel mains;

- *Network Control* – which includes network monitoring to ensure the network is operating within prescribed pressure limits and the maintenance associated with SCADA (Supervisory Control and Data Acquisition) facilities and field based telemetry equipment; and

- *Other Maintenance Costs* – which includes the ongoing maintenance of gas distribution assets, such as regulators, odorisers, city gates and line valves.

Envestra has included for the forecast period two additional opex categories called "Operating - Non-Base Year Costs" and "Maintenance - Non-Base Year Costs". These categories reflects those costs that are either of an operating or maintenance nature which are not reflected in the 2011 base year but are expected to be incurred over the 2013 to 2017 Access Arrangement period (and are discussed in section 6.7).

Each of the above cost categories is then adjusted (or rolled forward) to reflect forecast changes in labour and material costs over the 2013 to 2017 Access Arrangement period.

The 2011 base year opex, expressed in real 2011 dollar terms, is $52.4 million (excluding ARS).

6.5 Adjustment to Base Year Opex

The base year roll-forward approach is not an appropriate way to forecast certain costs that Envestra will incur over the 2013 to 2017 Access Arrangement period. This will be the case where either the amount included in the base year is not reflective of typical recurrent/annual expenditure or where it is not appropriate to adjust the cost by forecast changes in labour and/or materials costs.

The costs excluded from the 2011 base year include management fees and incentive payments made to the APA Group under the 2007 OMA and network development costs. The 2011 base year cost of $52.4 million has been adjusted by a total of $5.8 million to remove these amounts, of which $3.4 million reflects the removal of the management fee and incentive payments and $2.4 million reflects the removal of network development expenditure.

Because these costs are removed from the base year, it was necessary to develop a separate forecast of the costs. This section discusses the forecast of the management fee and incentive payments and network development expenditure that are included in the opex forecast for the 2013 to 2017 Access Arrangement period.

6.5.1 Network Management Fee and Incentive Payments

As explained in chapter 5, Envestra outsources the operation and management of its Network to the APA Group. Envestra does this to lower its costs because, as a significantly larger entity, APA is able to achieve economies of scale, scope and know-how that is not otherwise available to Envestra. These benefits are evident in the benchmarking evidence provided as part of this AAI, which shows that Envestra's productivity levels are consistent with good industry practice.

Under the terms of the 2007 OMA, Envestra pays APA its reasonable costs of operating and managing the network and a network management fee (NMF) equal to 3% of Envestra's revenue. Envestra also pays incentives to APA that allow APA to retain for 12 months one-third of the benefit of operating and capital cost reductions achieved. The NMF and incentive payments are not linked to labour and materials costs and therefore need to be forecast separately.

The NMF is relatively straight forward to forecast. Given its structure, Envestra has forecast the NMF by calculating 3% of the building block revenue (prior to the inclusion of the NMF), as set out in chapter 12. This amount is then allocated equally to operating and capital expenditure. The incentive payments have been calculated by taking the average of the incentive fees paid to APA over the 2008 to 2011 period. This forecast amount of $0.6 million has been applied in each year of the 2013 to 2017 Access Arrangement period (see table 6.1).

Table 6.1: Forecast NMF and Incentive Payments, 2013 to 2017

$m (real 2011)	2013	2014	2015	2016	2017	Total
NMF	2.8	3.1	3.2	3.4	3.7	**16.1**
Incentive Fee	0.6	0.6	0.6	0.6	0.6	**3.0**
Total	**3.4**	**3.7**	**3.8**	**4.0**	**4.3**	**19.2**

6.5.2 Network Development

Network development activity is undertaken to optimise the utilisation of Envestra's network by:

- maximising the number of connections, and maximising the average consumption per new customer connection; and
- retaining the number of connections, and increasing the average consumption per existing customer connection.

As noted throughout this AAI, the GFC has had a significant impact on the operation of the network over the 2008 to 2012 Access Arrangement period (for example, see chapter 2). One of Envestra's responses to the GFC was to reduce expenditure where this would not adversely impact on network safety and reliability. Network development was identified as one such cost that could be temporarily reduced.

While Envestra has now increased expenditure on network development, such that it has returned to pre-GFC levels, the amount of expenditure incurred by Envestra in the 2011 base year is not reflective of prudent and efficient expenditure. It is for this reason that it is not appropriate to apply a base year roll-forward approach to forecast network development expenditure. Rather than rolling forward past expenditure, Envestra has developed a network development plan over the 2013 to 2017 Access Arrangement period from a zero base.

Envestra's network development program for the 2013 to 2017 Access Arrangement period was developed after undertaking a strategic review of the opportunities and challenges for natural gas in the Victorian energy market. Individual programs have been defined to increase utilisation of the network. The strategy and specific programs are outlined in attachment 6.3. It is proposed that the program will apply in Victoria and Albury. Costs attributable to each network have been pro-rated according to customer numbers.

Forecast costs in $2011 for the 2013 to 2017 Access Arrangement period in Victoria are summarised in table 6.2.

Table 6.2: Forecast Network Development Expenditure, 2013 to 2017 (excl. Cost Escalation)

	Year					
$m (real 2011)	2013	2014	2015	2016	2017	Total
Total	**3.2**	**3.2**	**3.6**	**3.5**	**3.7**	**17.2**

6.6 Deriving 2012 Base Year Opex

The adjusted 2011 base year opex is then adjusted for forecast changes in cost escalation (see section 6.8) to derive a 2012 base year opex forecast.[98]

6.7 Non Base Year Opex

This section sets out opex that is not included in the 2011 base year but is forecast to be incurred over the 2013 to 2017 Access Arrangement period. There are essentially three reasons why such expenditure may not be reflected in the base year:

(1) the opex is associated with the delivery of a particular capital project; or

(2) the cost arises from a one-off opex project; or

(3) the cost represents a permanent (or step) change in opex (for example, arising from a change in a service standard or regulatory obligation).

These costs are explained in further detail in the remainder of this section.

6.7.1 Capex-Related Opex

There are several capex projects set out in chapter 7 that will also require an amount of opex to be incurred. The relevant projects are summarised below and explained in more detail in chapter 7 and the associated business cases that are referenced for each project (all of the business cases are set out in Attachment 6.1 to this AAI).

[98] The resultant 2012 base year opex forecast is not the same as the 2012 forecast of opex set out in chapter 3 given that certain costs have been removed for roll-forward purposes, as explained in section 6.5.

(1) Regional SCADA (Business Case VA02)

The capex forecast allows for the installation of SCADA capability in regional areas. Once installed, those facilities will require on-going regular preventative maintenance expenditure in accordance with good industry practice (which is an operating cost).

(2) Extensions to New Towns (Business Cases V100, V103)

The Victorian Government is seeking to extend natural gas across regional Victoria and encourage greater investment in the regions. The Government has made a commitment to invest $100 million over the next few years to support making reticulated natural gas available to homes and businesses in country Victoria.

Once the Network has been extended, there will be routine levels of maintenance (leak surveys, pipe location data provision, meter leak repairs and so on) associated with the expanded infrastructure.

(3) Knowledge Management (Business Case VA201)

The changing environment in which Envestra operates necessitates a need to better document the business knowledge held by employees and to develop a more formal process to manage the documentation developed. This project will require the development of a document management system.

The opex component of this project includes the tasks of scoping the best way to develop the management system along with the ongoing management and maintenance of the system.

(4) IT – Road Map Initiative (Business Cases VA202)

While the majority of the IT projects require capital expenditure, an amount of operating expenditure will be incurred as part of the “IT Road Map” suite of projects. This includes a range of IT initiatives aimed at improving the management of network assets. The opex component includes resourcing, annual licence and ongoing infrastructure operating costs associated with these projects.

6.7.2 One-off Opex Projects

There are several one-off (or non-recurrent) opex projects that are forecast to occur over the 2013 to 2017 Access Arrangement period. These projects are outlined in this section and explained in more detail in the business cases attached to this AAI.

(1) Holes in Meter Boxes (Business Case V17)

This project seeks to address a safety concern in relation to gas meter wall boxes. These boxes were historically installed in inner Melbourne, with the boxes recessed into cavity walls erected on building boundary lines because it was not possible to locate the meters externally.

There is a risk that, in certain circumstances, gas could flow into the wall cavity and roof space of a building, creating a risk of fire or explosion. This project involves the systematic inspection and rectification of installations. It is estimated that only 1% of the total meter installations in Victoria are affected.

(2) Pipeline Integrity Remediation Works (Business Case VA19)

Envestra owns 21 transmission pipelines across Victoria and southern New South Wales that assist it to provide reference services. Pipeline integrity management ensures that the infrastructure remains fit for purpose by implementing a systematic approach to design, construction, operation and maintenance activities and the application of prudent engineering principles.

Envestra plans to conduct an engineering investigation of the design life of these pipeline assets. The focus of the program is to gather data on the integrity of the pipelines in order to confirm the design life and whether further information is required regarding the structural integrity of the pipeline (e.g. through inline inspections).

(3) Pipe Saddle Support Repairs (Business Case V37)

It is planned to carry out a repair/rectification program for approximately 430 pipework saddle supports located in City Gate sites and Main Line Valve (MLV) pits to eliminate contact areas that are susceptible to corrosion.

(4) Gas Pipes in Drains (Business Case V40)

The aim of this project is to minimise the risks from gas pipes historically laid through stormwater drains and sewers. Such penetrations expose drain clearing contractors, the general public and gas consumers to risks of fire or explosion from gas escaping into the drain if pipes are ruptured during drain clearing operations. Gas could also travel via the stormwater drain or sewer and enter, and accumulate, within a dwelling or building. Both scenarios could result in subsequent fire or explosion, causing serious injury to people and potentially catastrophic damage to property.

This project involves training of operators in the use of new specialised equipment for internal pipe inspections and the targeted inspections of pipes, stormwater drains and sewers identified as a safety risk.

(5) Pipeline Signage Replacement (Business Case VA90)

It is planned to replace all transmission pipeline 'Warning' marker signs and a number of marker sign posts (estimated to be in the order of 7,600 and 350 replacements respectively) in order to comply with Australian Standard 1319 Safety Signs for the Occupational Environment and Australian Standard 2885.1 Pipelines-Gas and Liquid Petroleum Part 1: Design and Construction.

6.7.3 Permanent (or Step) Changes in Opex

This category relates to costs that Envestra will be required to incur on an ongoing (or permanent) basis. Envestra considers that in determining whether such a change in opex is appropriate, it is necessary to demonstrate that the increased costs are driven by:

(a) a change in the business environment arising from external factors (e.g. attributable to the imposition of new or changed obligations); or

(b) a desire to improve service levels in a manner that is in the long term interests of consumers; or

(c) an initiative to reduce long term costs to consumers; or

(d) an initiative to improve the safety of network service provision.

Each step change in costs that is required over the 2013 to 2017 Access Arrangement period is described in this section and referenced to the above criteria.

(1) Cost of Carbon (Business Case V91)

On 18 November 2011, the *Clean Energy Act 2011* came into effect. This new Act is part of a new package of legislation (referred to as the "carbon scheme") that will see a price on carbon emissions in place from 1 July 2012.

Envestra currently reports carbon emissions annually under the *National Greenhouse and Energy Reporting Act 2007*. Under the *Clean Energy Act 2011*, for each tonne of reported carbon emissions, Envestra will be required to purchase one carbon permit. The carbon scheme will impose additional operating costs on Envestra arising from:

(1) the cost of carbon permits that Envestra will be required to purchase;

(2) the costs associated with administering the purchase of permits; and

(3) the increased input costs arising from the impact that the carbon scheme will have on the costs of Envestra's suppliers.

Envestra has proposed an additional factor in the Tariff Control Formula to allow for the recovery of the actual costs associated with the purchase of carbon permits (see chapter 15). The impact on input costs has been incorporated into the forecast change to materials costs (see section 6.8).

This leaves administration costs, which have been forecast to occur as a permanent change in opex costs. The additional costs stem from the new requirements in relation to the purchase of the required carbon permits and otherwise administer the carbon scheme.

This step change meets criterion (a) in that it is related to a change in the regulatory obligations imposed on Envestra.

(2) Network Monitoring and Control (Business Case VA06)

Envestra plans to engage a contractor to provide a 24 hour x 7 day network pressure surveillance capability to facilitate immediate responses and appropriate actions to any SCADA pressure alarms. In summary, the project will provide for:

- an immediate response capability to any alarms;
- the ability to contact appropriate operations personnel both during and outside normal business hours; and
- the ability to assist with the management of emergency situations.

The operating expenditure relates to the provision of the above capability. The outcome of this project is an increase in the quality, safety and reliability of services provided in an alarm or emergency situation, resulting in a lessening of risk in the provision of network services.

This step change meets criterion (d), in that it is necessary in order for the business to be able to deliver the distribution reference services in a safe and prudent manner.

(3) Technical Training (Business Case VA23)

This project, which has an opex and capex component, is for the development of interactive online computer based training packages and e-courses to enhance learning and development of skills. The project provides for training resources currently held at fixed locations to be supplemented by a mobile training resource that will allow for the consistent delivery of a range of skills and competencies across a broad geographic footprint.

This step change meets criterion (d) in that appropriate training is an important element in the ability for the business to deliver reference services in a safe manner.

(4) Meter Station Charges (Business Case V26)

Envestra pays metering charges to GasNet for the operation of meters at injection points to the Network. A review of all of these metering facilities is conducted by GasNet on a tri-annual basis. The purpose of these studies is to assess the capability and capacity of each transfer metering station, and where necessary, to upgrade the metering station. In new areas, new metering stations may be required.

This business case pertains to the increase in operating expenditure arising from upgrades to four metering stations and the provision of new metering stations that are required in order to meet gas supply requirements over the 2013 to 2017 Access Arrangement period, including to maintain a safe and reliable supply to customers.

This step change meets criterion (d) in that it is necessary for the business to deliver reference services in a safe manner.

(5) Interval Metering Data Management (Business Case VA49)

This project, which has an opex and capex component, is for monthly meter reading of large customer sites and for the management of that data. While this is the continuation of current practice, the work was previously undertaken by AEMO and will now be required to be undertaken by Envestra. The capex is for the initial set-up costs (hardware, telemetry, etc.) while the ongoing opex relates to monthly meter read checks, IT support and internal information processing and analysis.

This step change meets criterion (b) in that it is necessary for the business to deliver reference services in a manner that is in the long term interests of consumers. In this instance, the level of service (ensuring that metering data accurately reflects customer consumption) is not actually being improved but maintained, due to the lowering of a service level by another entity. This step change also meets criterion (a) in that it is due to a change in the business environment arising from external factors.

(6) Graphical Information System Analyst (Business Case VA93)

A Graphical Information System (GIS) analyst will be employed in order to resolve spatially based queries, undertake analysis, design reporting capabilities and generate information products on behalf of the business. Currently, drafting personnel provide GIS support on a limited capacity, and as such, it is planned to develop these capabilities within the business to strengthen asset management assessments and resources.

This step change meets criterion (d) in that it is necessary for the business to deliver reference services in a safe manner.

(7) Increased Maintenance Rates (Business Case VA94)

There is currently a contract (which contract expires in April 2013) with an external service provider to perform maintenance works on the Network. The type of maintenance covered by this contract includes:

- leak repairs (first response and mains and services repairs);
- preventative maintenance (such as corrosion protection, leakage survey, pipeline patrol & inspections); and
- third party/retailer/customer requests (such as asset locations, poor supply investigations, relighting appliances, high account investigations).

This step change accounts for the forecast increase in costs when this contract is retendered, as such costs will be a step increase in costs above the costs incurred in the base year for the relevant operating expenditure.

This step change meets criterion (a) in that it is due to a change in the business environment arising from external factors.

(8) Increase in Insurance Costs (Business Case V400)

In order to forecast insurance costs, Envestra commissioned its insurance broker to provide an estimate of insurance costs for property and public liability (the major insurance costs) over the 2013 to 2017 Access Arrangement period. Those estimates indicate that there will be a real increase in insurance premiums, which has been reflected in the opex forecasts.
This step change meets criterion (a) in that it is due to a change in the business environment arising from external factors.

(9) Change in Regulatory Accounting Policy - Reactive Mains Replacement (Business Case V98)

Envestra's regulatory accounting policy for the Network has been to capitalise all mains replacement works, which consists of block replacement and small amounts of 'piecemeal' or reactive replacement. Envestra is proposing to align this regulatory accounting policy with that of its other networks, where reactive replacement is expensed due to it being recognised as repair work.

This change does not represent an increase in total costs but a transfer of costs from capex to opex.

(10) National Energy Customer Framework (Business Case VA46)

The National Energy Customer Framework (NECF) is a legislative package aimed at regulating the sale and supply of energy to consumers. In 2002, the Council of Australian Governments (COAG) conducted a review of the energy market and devised a set of reforms intended to nationally harmonise jurisdictional arrangements, develop greater efficiency and enhance consumer protections.

The reforms were subsequently agreed to by each jurisdiction in the Australian Energy Market Agreement (AEMA) in 2004. The Ministerial Council on Energy (MCE) was responsible for developing the national customer framework, which resulted in the lead legislation being enacted in March 2011, with state legislation expected to follow in early 2012.

The MCE and other State Ministers have agreed to work towards an implementation date of 1 July 2012 (or 1 January 2013 in respect of various Victorian gas-related obligations). A range of legislative and regulatory activities must be completed by jurisdictions, market bodies, regulators, retailers and distributors to facilitate the introduction of the national customer framework.

Envestra, along with other distributors, have been working with State and Federal Governments to implement the new framework in a timely and efficient manner. As the framework will be embedded in new legislation, Envestra will be bound by the obligations of the NECF.

In addition to Envestra's current regulatory obligations, the NECF requires a greater interface between distributors and customers through formal contractual relationships and creates new/different obligations between distributors and retailers. These obligations are difficult to meet considering that each distributor has different operational practices and their level of interaction with customers and retailers varies considerably between jurisdictions.

To meet its obligations and ensure compliance, Envestra requires additional resources in the form of labour, IT systems and infrastructure to facilitate the interaction with gas consumers together with managing and co-ordinating the business changes and workflows that the NECF imposes. The business will incur additional opex and capex as a result of the introduction of NECF.

This step change meets criterion (a) in that it is related to a change in the regulatory obligations imposed on Envestra.

6.7.4 Summary of Non-Base Year Costs

The following table sets out all of the non-base year costs by year for the 2013 to 2017 Access Arrangement period.

Table 6.3: Non-Base-Year Costs Forecast, 2013 to 2017 (excl. Cost Escalation)

Non Base-Year Costs $m (real 2011)	2013	2014	2015	2016	2017	Total
Opex Related to Capex	0.0	0.7	0.7	1.4	1.5	**4.3**
One-off Opex Projects	0.8	1.0	0.9	0.4	0.4	**3.6**
Step Changes	4.1	5.6	5.7	5.8	5.8	**27.1**
Total	**4.9**	**7.4**	**7.4**	**7.6**	**7.8**	**35.1**

6.8 Net Growth Opex (Business Case V500)

Envestra will incur additional opex as the net number of customers added to the network increases. Envestra is forecasting to connect, on average, 12,000 net new volume customers to the network in each year of the 2013 to 2017 Access Arrangement period. The incremental cost stemming from new customer connections primarily includes meter reading, data processing and billing.

The Victorian Gas Distribution Code has established a benchmark incremental cost per new customer connection for the purposes of determining any customer contributions that might be required in respect of a connection request.[99] Envestra has applied this benchmark rate of $19.90 in 2011 dollar terms to forecast the incremental cost associated with new customer connections.

6.9 Cost Escalation

Envestra, along with the two other Victorian distributors, engaged BIS Shrapnel to provide an independent and expert opinion regarding the level of anticipated changes in labour (net of productivity gains), material and contractor costs in the 2013 to 2017 Access Arrangement period (see attachment 6.4). This is required in order to derive best estimates of forecast opex that are arrived at on a reasonable basis as required by the NGR.

BIS Shrapnel provided forecasts for the following four input cost categories that are relevant to the provision of reference services:

- *General labour* – this includes clerical/administration, professionals and managerial staff providing mainly administration and corporate services. The escalator chosen for this category is the movement in Average Weekly Ordinary Time Earnings (AWOTE) in the Property and Business Services (PBS) sector;

- *Electricity, Gas and Water (EGW) labour* – this includes gas network-related labour, which includes a range of skilled labour involved in construction, maintenance, design and operation of gas networks. The escalator chosen for this category is the movement in AWOTE for the EGW sector;

- *Network materials* – this includes mainly polyethylene pipe. BIS Shrapnel derived an escalator based on movements in the international crude oil price (in $US per barrel). Crude oil is a key ingredient in the manufacture of thermoplastic resins, which is the main material used in polyethylene pipe;

[99] ESCV "Gas Distribution System Code" (Version 9.0 effective from 1 January 2009) Date 12 December 2008 page 45

- *General materials* – applicable to general materials (i.e. other than network-specific materials).

The labour escalator could have been based on the AWOTE or Labour Price Index (LPI). The former has been applied given that Envestra is adjusting the labour escalator for forecast changes in labour productivity over the 2013 to 2017 Access Arrangement period. This is because, unlike the LPI, the AWOTE measure includes all the components of productivity improvement that will be included in the adjustment for labour productivity.

Envestra has sought the advice of Professor Jeff Borland on whether the AWOTE or LPI should be used for the purposes of real labour cost escalation over the 2013 to 2017 Access Arrangement period. Professor Borland, who is an expert in the operation of labour markets in Australia, notes that:

> *"The LPI wage measure does not incorporate the effect on labour costs of changes in the skill composition of the workforce. But the labour productivity measure does incorporate the effect of changes in the skill composition of the workforce. Hence, subtracting the change in labour productivity from the change in LPI, involves using a measure of wage costs that incorporates different effects of labour productivity than the labour productivity measure being used. The measure of the change in productivity-adjusted LPI therefore underestimates the change in labour costs by the amount of the 'Change in Composition productivity effect'.*
>
> *Put in a different way, LPI does not incorporate the effects on productivity of changes to the skill composition of the workforce. But the labour productivity measure used to adjust LPI does include the effects of changes to the workforce skill composition. Hence, when the latter measure is subtracted from the former, changes to labour costs are under-estimated by however much changes in the skill composition of the workforce have affected labour productivity.*
>
> *By contrast, the AWOTE measure incorporates exactly the same effects of changes to labour productivity as the measure of labour productivity. Hence, subtracting the latter from the former nets out exactly the productivity effect that is included in the wage measure; and thus gives a correct measure of the change in labour costs."*[100]

The 'change in composition productivity effect' referred to by Borland refers to changes in labour costs and productivity driven by structural changes in the mix of skilled workers. The fact that the LPI excludes the impact of compositional impacts appears to be generally well accepted.[101] However, there have been different views expressed in the past over the required adjustment to the LPI to take into account the fact that the LPI excludes compositional productivity impacts.

Deloitte Access Economics (DAE), who has historically advised the AER on this matter, have argued that the compositional change in the skill of the workforce has not had a significant impact on productivity in the utilities sector. Professor Borland, based on his quantitative analysis of national accounts data, concludes that the impact is likely to account for around 1% on average per year (see attachment 6.5). This led Professor Borland to state that:

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100 Borland 2012, 'Labour Cost Escalation: Choosing Between AWOTE and LPI', Report Prepared for Envestra March 2012.

101 For example, see Deloitte Access Economics 2011, 'Productivity measures to adjust LPI and AWOTE', Report Prepared for the AER, 8 November 2011, pg. 4.

> *"I disagree with DAE's argument that changes in average labour quality can be regarded as sufficiently small to be excluded from the analysis. I do accept that in recent times there has been a slow growth in aggregate labour productivity. But this is not to say that this can be considered a permanent feature of the Australian labour market."*

Overall, Professor Borland finds that the AWOTE is the most reasonable measure of labour costs when adjusting for productivity. Envestra has therefore applied the AWOTE measure as the best estimate of labour escalation over the 2013 to 2017 Access Arrangement period.

Forecast opex has been split into the previously mentioned four input cost categories for which BIS Shrapnel determined cost escalators. This was based on an average of the historical breakdown of actual expenditure where that data was available. Depending on the available data, the average was taken over either a four or five year period. The cost escalator derived by BIS Shrapnel was then applied to the average composition of costs for each opex category to derive forecast opex.

There are a number of factors identified in chapter 2 and by BIS Shrapnel that are expected to put considerable pressure on input costs over the 2013 to 2017 Access Arrangement period, which includes the:

- *Mining and Resources Boom* – significant global demand for minerals has led to unprecedented levels of investment in mining and exploration, which investment was around \$62 billion in 2010/11 (reflecting the highest expenditure on record and a 50% increase from 2009/10). This level of investment is expected to increase to over \$70 billion in 2011/12 and continue at these levels given the positive outlook for commodity prices over the medium term;[102]

- *Nation Building Program* - the Federal Government has committed \$37 billion to fund critical infrastructure in the transport, communications, water and energy sectors of the economy;

- *National Broadband Network (NBN)* - in addition to the Nation Building Program, the Federal Government has committed a further \$37 billion to build a superfast NBN, which is the single largest infrastructure project in Australia's history;

- *Energy Network Renewal* - electricity and gas networks across Australia have embarked on major network refurbishment, extension and augmentation programs that are directed at improving reliability levels and addressing ageing asset profiles;

- *Coal Seam Gas* - several significant investment decisions have recently been confirmed to process coal seam gas into liquefied natural gas (LNG), which will require more than \$100 billion in infrastructure investment over the next five years for extensive drilling of gas wells and the development of significant gas networks to transport gas;

- *Introduction of a Carbon Price* - which is expected to trigger significant investment in gas-fired power stations along with new renewable generation facilities over the next decade; and

- *Recent Natural Disasters* - the Queensland and Victorian floods in early 2011 and 2012 require significant investment to restore the infrastructure and building damage caused by the floods in those states.

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[102] See New, R, Ball, A, Copeland, A et al. 2011, "*Minerals and energy, major development projects – April 2011 listing*", ABARES, Canberra, May.

The above list is not comprehensive and merely sets out examples of the activity that is to occur over the 2013 to 2017 Access Arrangement period. This level of activity is unprecedented and will create a significant demand on skilled labour. This explains why BIS Shrapnel has forecast EGW and Construction wages to accelerate and grow faster than the All Industries average.

The following table sets out the escalators as determined by BIS Shrapnel.

Table 6.4: Labour and Materials Escalators, 2012 to 2017

Real adjusted for Productivity	2012	2013	2014	2015	2016	2017
EGW Labour	1.6%	3.0%	6.6%	4.1%	1.0%	-0.1%
General Labour	1.9%	3.0%	6.8%	3.6%	0.7%	0.6%
Network Materials	-2.7%	2.7%	11.5%	4.4%	-2.5%	4.0%
General Materials	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

6.10 Expert Review of Opex

Envestra engaged PB Associates to assist it to develop various business cases that comprise the non base year opex component of forecast opex. In particular, PB examined the underlying assumptions and parameters supporting the respective operating expenditure. This external review was undertaken to ensure that Envestra's opex forecasts were compliant with all relevant requirements set out in the NGR, including that the forecasts represented best estimates arrived at on a reasonable basis.

6.11 Summary

As set out in this chapter, the forecast operating expenditure has been arrived at by:

(1) determining base year opex by taking opex in the most recent year for which actual information is available, which in this case is 2011. The 2011 base year opex is $52.4 million (see section 6.4);

(2) adjusting the 2011 base year opex for those costs where the 2011 base year roll-forward approach is not appropriate, which in this case relates to the NMF and incentive payments (see section 6.5.1) and network development costs (see section 6.5.2). These two adjustments result in a $5.8 million adjustment to the 2011 base year opex;

(3) escalating the adjusted 2011 base year opex for forecast changes in labour and materials costs in 2012, which results in opex of $47.6 million in 2012 (see section 6.6);

(4) adding back the NMF and incentive payments, network development costs and non base year opex, which on average amounted to an additional $14.3 million per year (see sections 6.5.1, 6.5.2 and 6.7);

(5) adding growth opex by determining the incremental cost of supplying new customers that are forecast to be connected to the network, which on average amounted to an additional $3.7 million per year (see section 6.8); and

(6) escalating forecast opex for expected changes in labour and material costs, which on average amounted to an additional $8 million per year, noting that cost escalation compounds on a yearly basis (see section 6.9).

The resultant build-up of our forecast operating expenditure is shown in table 6.5.

Table 6.5: Build-up of Forecast Operating Expenditure, 2011 to 2017

Opex Summary $m (real 2011)	2011	2012	2013	2014	2015	2016	2017
Base Year Roll-forward (Steps 1 to 3)	46.6	47.6	47.6	47.6	47.6	47.6	47.6
Add:							
NMF and Incentive Payments (Step 4)			3.4	3.7	3.8	4.0	4.3
Network Development (Step 4)			3.2	3.2	3.6	3.5	3.7
Non-Base Year Opex (Step 4)			4.9	7.4	7.4	7.6	7.8
Incremental Growth Opex (Step 5)			0.2	0.5	0.7	1.0	1.2
Cost Escalation (Step 6)			2.2	7.1	9.9	9.8	10.8
Total Operating Costs (excl. ARS)			**61.5**	**69.5**	**73.0**	**73.6**	**75.4**
ARS			2.3	2.3	2.3	2.4	2.4
Total including ARS			**63.8**	**71.8**	**75.4**	**76.0**	**77.8**

The forecast operating expenditure by category is summarised in table 6.6 and figure 6.1. A spreadsheet model showing how the operating expenditure forecast has been derived is provided in attachment 6.6.

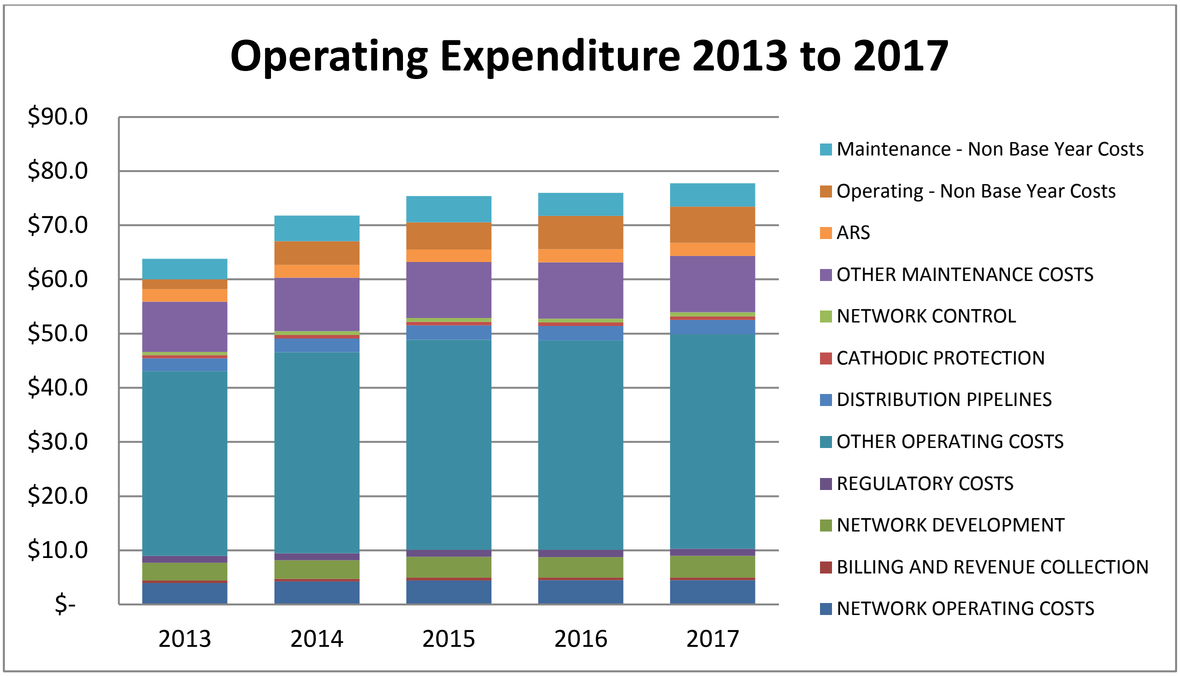
The forecast operating expenditure for the 2013 to 2017 Access Arrangement period set out in tables 6.5 and 6.6 is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing reference services.

Envestra has adopted methodologies to derive its forecast operating expenditure that are consistent with that used by Envestra and accepted by the AER in previous reviews. Envestra has also, wherever possible, relied upon historical information to derive its forecasts and has sought to incorporate into its forecast all factors that impact on the delivery of reference services. Envestra therefore considers that its forecasts reflect best estimates that are arrived at on a reasonable basis and comply with rule 91.

Table 6.6: Forecast Operating Expenditure, 2013 to 2017

Opex Summary $m (real 2011)	2013	2014	2015	2016	2017	Total
Operating Costs						
Network Operating Costs	4.0	4.3	4.5	4.5	4.5	**21.7**
Billing and Revenue Collection	0.4	0.5	0.5	0.5	0.5	**2.4**
Network Development	3.2	3.4	3.9	3.8	4.0	**18.3**
Regulatory Costs	1.3	1.3	1.3	1.3	1.3	**6.6**
Other Operating Costs	34.1	37.1	38.7	38.7	39.6	**188.1**
Operating - Non Base Year Costs	1.8	4.4	5.0	6.2	6.7	**24.1**
Total Operating Costs	**44.9**	**51.0**	**53.9**	**54.9**	**56.5**	**261.2**
Maintenance Costs						
Distribution Pipelines	2.4	2.5	2.6	2.7	2.7	**12.9**
Cathodic Protection	0.6	0.6	0.7	0.7	0.7	**3.2**
Network Control	0.6	0.7	0.7	0.7	0.7	**3.5**
Other Maintenance Costs (incl. Leak Repairs)	9.3	9.9	10.3	10.4	10.4	**50.3**
Maintenance - Non Base Year Costs	3.8	4.8	4.9	4.2	4.4	**22.0**
Total Maintenance Costs	**16.6**	**18.5**	**19.2**	**18.7**	**18.8**	**91.9**
Total Ancillary Reference Services	2.3	2.3	2.3	2.4	2.4	**11.7**
Total $m	**63.8**	**71.8**	**75.4**	**76.0**	**77.8**	**364.8**

Figure 6.1: Forecast Operating Expenditure 2013 to 2017



7. Capital Expenditure

7.1 Introduction

Capital expenditure (capex) that is forecast to occur within the 2013 to 2017 Access Arrangement period is based on the level necessary to allow Envestra to meet the relevant requirements of the National Gas Rules (NGR), including to satisfy the forecast growth in demand for services, to maintain and improve safety, to improve system integrity and to comply with various regulatory obligations.

This chapter summarises the capex forecasts for the 2013 to 2017 Access Arrangement period. The detailed reasoning for the proposed capex program, particularly in relation to the mains replacement expenditure, is attached to this Access Arrangement Information (AAI). These more detailed reasons should therefore be read in conjunction with this chapter.

The AER has requested in its Regulatory Information Notice (section 10.1(a)) that Envestra identify the materiality threshold used for forecasting capex. Envestra has adopted a "bottom-up" approach to developing its forecast capex where all aspects of the business have been subject to detailed review. Envestra has therefore not set a defined materiality threshold, which is also consistent with how its internal annual budgets are prepared.

The key component of Envestra's proposed capex relates to the on-going replacement of ageing mains. The mains replacement program set by the regulator for the current period was not achieved due to the Global Financial Crisis (GFC). The program proposed for the 2013 to 2017 Access Arrangement period seeks to implement the program approved by Energy Safe Victoria (ESV) in respect of the mains replacement program.

This chapter sets out the relevant requirements of the NGR as it relates to forecast capex. This chapter then outlines the approach taken by Envestra to develop its forecast capex program, including a discussion of the key overarching plans guiding that forecast. The forecast capex is then explained in the remainder of this chapter.

7.2 Requirements of the National Gas Rules

Rule 78 of the NGR provides for the projected regulatory capital base to include forecast conforming capital expenditure for the period.

Rule 79(1) states that:

> *(1) Conforming capital expenditure is capital expenditure that conforms with the following criteria:*
>
> > *(a) the capital expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services;*
> >
> > *(b) the capital expenditure must be justifiable on a ground stated in subrule (2).*
>
> *(2) Capital expenditure is justifiable if:*
>
> > *(a) The overall economic value of the expenditure is positive; or*

(b) The present value of the expected incremental revenue to be generated as a result of the expenditure exceeds the present value of the capital expenditure; or

(c) The capital expenditure is necessary:

(i) To maintain and improve the safety of services; or

(ii) To maintain the integrity of services; or

(iii) To comply with a regulatory obligation or requirement; or

(iv) To maintain the service provider's capacity to meet levels of demand for services existing at the time the capital expenditure is incurred (as distinct from projected demand that is dependent on an expansion of pipeline capacity)

In addition, rule 74 states that in relation to forecasts and estimates:

(1) Information in the nature of a forecast or estimate must be supported by a statement of the basis of the forecast or estimate.

(2) A forecast or estimate:

(c) Must be arrived at on a reasonable basis; and

(d) Must represent the best forecast or estimate possible in the circumstances.

7.3 Development of Capital Expenditure Program

Envestra's capital expenditure forecast has been developed using a "bottom-up" approach. This has required Envestra to undertake a detailed review of all aspects of the business to ensure that the proposed capex program will comply with all relevant requirements of the NGR, including to:

- maintain, and in some cases improve, safety in order to minimise risk to consumers, the public and third parties;
- maintain, and in some cases improve, reliability and customer service;
- maintain capacity to meet forecast demand;
- maintain acceptable levels of business risk; and
- to comply with all relevant regulatory obligations.

This section outlines the key business plans guiding the development of the capex program, the process followed by Envestra to develop the scope of its capex program and the methods adopted to determine the cost of the capex program.

7.3.1 Overarching Business Plans

The capex program for the 2013 to 2017 Access Arrangement period has been developed pursuant to Envestra's Asset Management Plan.

The Asset Management Plan (AMP) provides a consolidated view of a number of technical and operational plans and describes how these plans are used to drive asset management strategies and expenditure to ensure safe, reliable and sustainable supply of gas in line with our legislative obligations, effective risk management, financial business parameters, lowest lifecycle costs and extraction of maximum value from assets.

There are a number of plans that are subordinate to the AMP, including the:

- *Mains Replacement Plan (MRP)* – which provides the basis and justification for the replacement of mains that have reached the end of their useful life;

- *Capacity Management Plan* – which describes the processes underpinning network design and analysis for ensuring that the Network has the capacity to deliver gas at sufficient pressure and quality to meet the forecast demand for services; and

- *Field Life Extension Sampling Plan* – which provides the basis on which gas meters are periodically tested for accuracy, which in turn determines how long meters are able to stay in service before needing replacement or refurbishment.

All plans have been subject to extensive review, including as part of the regulatory review process for the 2008 to 2012 Access Arrangement period. These plans govern the timing and approach to undertaking, among other things, asset replacement and/or augmentation works that are necessary to ensure that Envestra's regulatory obligations are met over the long term.

In addition to the above, Envestra has prepared detailed business plans relating to specific capital expenditure requirements for the 2013 to 2017 Access Arrangement period. PB Associates were engaged to test that key business plans were robust and consistent with the relevant requirements of the NGR. Forecast capex was also reviewed by senior management at APA and Envestra and endorsed by the Envestra Board.

The Asset Management Plan, Mains Replacement Plan and Capacity Management Plan have been provided as attachments to this AAI.

7.3.2 Planning and Approval Process

Envestra has strict planning and approval processes to ensure that its capital expenditure is prudent, efficient and consistent with good industry practice. This involves the rigorous application of technical, managerial and financial governance processes to ensure that expenditure meets its legal, regulatory and operational obligations in a manner that achieves the lowest sustainable cost of providing reference services.

A range of controls are applied throughout the life-cycle of a project or works program. In initial design phases, alternatives for projects are explored and life-cycle asset management principles employed to determine an appropriate balance of key factors (e.g. project timing, risk, reliability and so on). Gas demand and network modelling is used to update network parameters and to ensure that network capability is sufficient given forecast demand requirements.

In each case, augmentation projects are timed in order to ensure that minimum supply pressures are maintained in all parts of the network, as determined by the network modelling and load growth factors. Augmentation works are delayed where load growth or other parameters do not eventuate and it can be demonstrated that augmentation/investment can be prudently deferred without compromising reliability or safety.

Wherever possible, network alterations and extensions are timed to coincide with works undertaken by road authorities and other utilities, in order to minimise the cost as well as minimising disruption to the public. For example, Envestra will seek to coordinate laying new mains with the laying of other services such that trenching is only done on one occasion and not on two separate occasions.

Cost estimators liaise closely with operations personnel to ensure that the costing of projects takes account of historic trends in costs and, when combined with accounting system outputs and regular audits of projects, ensures a sound feedback loop so that confidence can be placed on estimating/forecast outcomes. Actual outcomes are routinely compared against forecast/budget parameters.

For network extensions required for customer connections, economic modelling is undertaken to determine whether the connection passes the economic test under the Rule 79(2) (b). Where the connection does not satisfy this rule, a capital contribution is sought from the new customer(s)[103].

As part of normal business cost control protocols, project approval takes place at various levels within the business, taking into account whether the expenditure has been budgeted as well as the value of the project, with larger projects (i.e. more than $1 million) requiring Envestra Board approval.

7.3.3 Forecasting Lowest Sustainable Costs

Capital expenditure mostly falls into the following three categories of activity:

- *Routine projects* – which includes the on-going day to day operation of the network. These forecasts are derived on the basis of (multiplying) unit rates and forecast demand for the particular activity (e.g. customer connections, mains renewal);

- *Recurrent projects* – which includes activities that vary in scope or nature but reoccur on an annual (or regular) basis, which are somewhat predictable and for which the historical spend is usually indicative of future spend (e.g. replacement of plant and equipment, ad-hoc network reinforcement); and

- *Non-recurrent projects* – which are projects that require individual costing due to their size, scope or uniqueness (e.g. IT projects).

Expenditure on tasks that are of a routine (or repetitive) nature are more easily forecast due to the availability of historical unit rate data. However, an important consideration is the degree with which historical cost information is a reliable predictor for the forecast period. Factors which may affect/alter unit rates overtime include:

- *Changes in labour and material costs* - industry-wide cost escalators prepared by independent experts are commonly used to forecast generic changes in labour and material costs over time;

103 The AER has requested (RIN section 4.12(f)) details of contractual agreements with parties where capital contributions are made. However, there are no on-going contracts with consumers insofar as capital contributions are concerned, as these are one-off payments.

- *Changes in work scope* – includes changes in the content, process or geography of a particular project, such that the unit of work (or the mix of work) to be undertaken is not the same as that undertaken in the past (e.g. laying mains or services in new estates versus established suburbs). This is an important consideration in the context of new connections, where relatively more connections are taking place in "in-fill" (or existing areas). This is relevant because connections associated with urban consolidation (i.e. in brownfield conditions) are more costly than those taking place in new estates (i.e. in greenfield conditions); and

- *Volume of work* – periods of high/low activity may to lead to changes in unit costs in accordance with the economies of scale, or conversely with scarcity of labour.

Historical unit costs have been used as the default starting point for deriving forecast unit costs. This is appropriate given the strong regulatory and commercial incentives faced by Envestra to reduce costs over time. Indeed, it is for this reason that regulators, including the AER, have relied on past expenditure to forecast costs going forward (for example, the use of a "base year roll-forward" approach to forecasting operating expenditure).

In many cases, however, historical unit rates will vary over the forecast period. Consequently, choosing the latest unit rate, or one particular year's unit rate, may not provide the best estimate for forecasting, in which case an average over 2-3 years may be more accurate. This has been done in establishing the base for many of the unit rates for the forecast period.

Once appropriate historical unit costs were determined, any factors materially affecting those costs going forward (as per the examples described above) were identified and an adjustment applied to the historical unit rate where appropriate. This process ensures that a "best estimate" forecast of the unit rate is used in forecasting capex.

In regard to labour and material cost escalation, Envestra engaged BIS Shrapnel to provide an independent and expert assessment of expected changes in labour and material costs to apply in the forecast period (see attachment 6.4). Envestra has applied the BIS Shrapnel escalators to the respective input cost components of the capex forecast (see section 6.9 and 7.6).

Forecasts of unit demand for respective categories of capex and other detailed information relating to the formulation of "best estimate" forecasts are contained within the respective expenditure categories as set out in the remainder of this chapter and in more detail in attachments 7.1 and 7.5. Forecasts have been developed to incorporate any specific changes in circumstances over the 2013 to 1017 Access Arrangement period where they are known.

Attachment 7.1 sets out the unit rates relevant to the capex forecast, their historical level and any factors impacting unit rates going forward. Wherever applicable, recent tendering results have been used to ensure that forecast costs represent best estimates.

7.3.4 Cost Monitoring and Control Process

As discussed in chapter 5, Envestra outsources the operation and maintenance of the network to the APA Group. This outsourcing structure is a fundamental part of Envestra's business strategy. The structure allows Envestra to achieve efficient cost outcomes by accessing the economies of scale, scope and know-how of the considerably larger APA Group. The terms of the outsourcing contract are set out in the 2007 Operating and Management Agreement (the 2007 OMA).

There are strict cost management processes set out under the 2007 OMA. This includes the annual budgeting process followed by Envestra and APA. Mr Ferguson, APA's General Manager – Networks, has described in his affidavit that the budget setting process involves significant debate over the appropriate unit rates and that there is continuous pressure to drive unit rates and costs down:

> "*At the first and subsequent meetings between APA and Envestra referred to above, there is vigorous debate about the activities to be undertaken during the budget year, the volume of gas to be delivered, and the unit rates such as the cost per repair, the cost per metre for construction, the cost per correction of a leak etc. Envestra always heavily challenges any upward shift in rates and continuously presses for a reduction in rates. The Envestra representatives challenge how the rates are calculated or set and routinely require evidence for and justification of the opex and capex comprised in the budget. There is a constant tension in these meetings between APA's obligations under the OMA and making sure APA can deliver the required service on the one hand and Envestra's budgeting requirements and constant pressure to drive down costs on the other hand*"[104].

Once the budget is set, APA reports at the end of each month on all of the budgeted activities, with a focus on comparing actual performance against budget performance. The monthly reports are very detailed and require extensive explanation of reasons for any variation to budget. Mr Ferguson, in his affidavit, describes the cost monitoring and control process as a *"rigorous and often abrasive process with Envestra relentlessly pursuing the driving down of costs and increased efficiencies."*

This cost monitoring and control process, together with the planning and approval processes described in section 7.3.2, ensures that capex is prudent and efficient and consistent with good industry practice and the achievement of lowest sustainable costs from the point of approval to project completion for:

(a) capital expenditure undertaken in the 2008 to 2012 Access Arrangement period; and

(b) capital expenditure to be undertaken in the 2013 to 2017 Access Arrangement period.

The capex to be incurred in the forecast period is discussed in the remainder of this chapter.

7.4 Forecast Capital Expenditure

This section sets out Envestra's forecast capex over the 2013 to 2017 Access Arrangement period. This includes a discussion of the scope of the proposed works, key cost drivers and forecast expenditure (expressed in 2011 dollar terms and before the application of escalators and overheads). The more detailed reasoning for the proposed capex is in some cases set out in the business cases that are contained in Attachment 6-1.

7.4.1 Key Investment Drivers

The level of capital expenditure over the 2013 to 2017 Access Arrangement period is driven predominantly by the following key drivers:

[104] See affidavit of John Ferguson.

(a) *Asset condition* – this is derived from an engineering assessment of an asset's (or class of assets') physical and functional characteristics to determine its suitability for continued service. Past reliability, likelihood of asset failure, and consequence of asset failure are all considered as part of this assessment. Investment is required when the asset condition is such that the ability to maintain the reliability, safety and security of the network is compromised or begins to impair the ability to supply services of sufficient quality, reliability and security (irrespective of the expected useful life of the asset).

Particularly in relation to gas distribution, assets that fail in service may place the community at risk. Envestra balances the risks and on-going costs of maintenance versus replacement of assets, and where asset failure risks are high and reliability or safety issues are present or likely, assets are recommended for replacement. A cornerstone of Envestra's capital expenditure over the forecast period is the Mains Replacement Plan, which represents an efficient long-term strategy to not only improve safety, but also deliver improved capability and reliability in respect of the services provided.

(b) *Demand growth* – much of this investment is reactive in that Envestra must respond to demand for connections and ensure that the network has the capability to meet the increasing peak demand. Gas networks are designed to accommodate peak hourly demand. Unlike transmission pipelines, gas networks contain relatively little gas storage (or linepack) and therefore must be able to respond almost instantaneously to demand. A key driver of increases in peak demand is the increasing use of high-flow instantaneous gas hot water heaters, which are replacing the more traditional storage water heaters. Instantaneous heaters have higher peak demand requirements (despite using less gas), thereby placing a much higher stress on the network.

(c) *Reliability* – the Victorian Gas Distribution Code prescribes a minimum pressure requirement at the outlet of a gas meter (1.1 kPa) and stipulated minimum pressures at the fringes of a network. Envestra is required by the Code to use all reasonable endeavours to maintain sufficient distribution system pressures to ensure that the minimum stipulated pressure is maintained.

Accordingly, Envestra has identified areas of the network that have experienced supply issues or are prone to loss of supply due to the way the network has developed over time. Where the risk of loss of supply is assessed as likely, augmentation works have been identified to overcome any shortcomings in security of supply.

As discussed above, a particular issue with the Network is that average domestic consumption is declining but peak hourly consumption is increasing, reflecting the increasing use of more efficient, but instantaneous, gas appliances (see chapter 13). This means that parts of the network that were previously reliable are increasingly at risk of being unable to provide gas at the appropriate pressure during peak periods, thereby requiring network augmentation.

The above three factors are taken into consideration in Envestra's AMP for the Network (Attachment 7.2). As noted earlier, the AMP documents the interrelationship of a number of technical and operational plans and how these are used to drive asset management strategies and actions to ensure a safe, reliable and sustainable supply of gas in line with:

- regulatory obligations – particularly rule 79 of the NGR;
- effective risk management – as per the policy and procedures set out in the Asset Management Plan and its subordinate plans;

- lowest lifecycle costs – such that costs over the long term are minimised; and
- good industry practice – as the procedures and processes adopted by Envestra conform with industry best practice.

The AMP:

- demonstrates that Envestra's asset management approach results in capital expenditure that is prudent, efficient, in accordance with accepted good industry practice and consistent with achieving lowest sustainable costs;
- provides a technical basis to support Envestra's capital expenditure program; and
- provides the basis for continuous improvement of asset management practices.

7.4.2 Mains Replacement

Mains replacement relates to the replacement of gas mains and inlet services in order to deliver gas safely and efficiently, as set out in the MRP, which is set out in Attachment 7-4.

As at August 2011, the Network contained approximately 1,100 km of aged mains, of which around half is lead-yarn jointed cast iron pipe. Envestra has been undertaking a program for replacement of these mains over many years, which is necessary in order to maintain public safety and minimise the amount of gas lost through leakage. Most of the leakage occurs by seepage through the deteriorated lead-yarn joints of these old cast iron pipes. Leakage of gas must be minimised in order to:

(a) minimise the risk of fire/explosion;

(b) contain increasing operational costs associated with the repair of gas leaks;

(c) minimise the cost to the customer of gas required to be purchased to replace leaking gas; and

(d) minimise greenhouse gas emissions (natural gas has a greenhouse impact that is 21 times that of carbon dioxide).

Replacement of old pipes is also necessary because they are limited to operating at low pressures. This limits their capacity to provide high volumes of gas at peak periods, contributing to poor reliability. In addition, occasionally the ingress of water into mains which operate at low pressure results in blockages and loss of supply. In some cases, the low operating pressure (and consequently low linepack and low capacity) means that new connections cannot be made. Newer pipes (consisting of polyethylene or coated steel), however, can operate at high pressures (350 kPa versus 1.5 kPa) and therefore do not have this constraint.

In the 2008 to 2012 Access Arrangement period, Envestra had planned to replace 570km of mains. However, as explained in chapter 2, Envestra had to curtail expenditure for a period of time due to the GFC. Consequently, by the end of this Access Arrangement period Envestra expects to have replaced around 400km of main. In 2010, Energy Safe Victoria (ESV) expressed its concerns to Envestra in relation to the delay in the mains replacement program:

> *"ESV was and remains significantly concerned …that Envestra were not fulfilling their obligations under the 2008 access arrangements and furthermore were not intending to replace the old cast iron mains as outlined in the asset management plan of 2006."*

And:

> *"Envestra have indicated that the deterioration of the network will be managed [during the GFC] through surveillance and repair rather than a replacement program and that the numbers of outstanding leaks has been considerably reduced. This strategy will not however detect or mitigate a catastrophic failure of cast iron which puts the public and Envestra at risk"*[105]*.*

ESV consequently indicated that it would not approve Envestra's Asset Management Plan until it was amended to reflect that the mains replacement program would still be completed by 2020. Envestra amended its AMP in June 2010 accordingly. The forecast set out in this submission is consistent with that AMP, as explained in the MRP.

The capital expenditure associated with the mains replacement program satisfies Rule 79(2) as follows:

- 79(2) (c) (i) – the capital expenditure is necessary to maintain and improve the safety of services. The MRP will reduce the incidence of gas leaks and hence improve the safety of services provided by Envestra. The safety of consumers and the public is of paramount importance to Envestra, as is the safety of operational staff involved in the repair of gas leaks;

- 79(2)(c)(ii) – the capital expenditure is necessary to maintain the integrity of services, as it will result in the:

  - elimination of outages due to water ingress;

  - elimination of supply loss arising from leak repair works; and

  - elimination of poor pressure (or loss of supply) at customers' premises due to peak loading on low pressure mains.

- 79(2)(c)(iv) – the capital expenditure is necessary to maintain the service provider's capacity to meet levels of demand for services existing at the time the capital expenditure is incurred (in those areas where low pressure mains are unable to satisfy peak demand or allow the connection of new customers, the mains replacement is necessary to maintain capacity to meet levels of demand for services); and

- 79(2)(c)(iii) - the capital expenditure is necessary to comply with the regulatory obligations set out in the Gas Safety Act, particularly section 32 which requires Envestra to "minimise as far as practicable the hazards and risks to the safety of the public and customers, and minimise the risk of damage to property arising from the distribution of gas".

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105 ESV letter to Envestra dated 4 May 2010

The following table sets out the forecast cost of mains replacement.

Table 7.1: Mains Replacement Forecast, 2013 to 2017 (excl. Cost Escalation and Overheads)

Mains Replacement Program	2013	2014	2015	2016	2017	Total
Length km	150	140	125	115	105	**635**
Total ($m, real 2011)	**59.7**	**63.6**	**52.6**	**53.4**	**53.4**	**282.7**

7.4.3 Residential and I&C Meter Replacement

Envestra is required to periodically change gas meters in order to test them for metering accuracy. These periodical meter changes (PMCs) take place at intervals (approximately 10-15 years) authorised by the Australian Energy Regulator (AER). This continuous changeover and testing program ensures that each gas meter continues to operate within prescribed tolerances. The obligations and associated processes are set out in Envestra's Field Life Extension Sampling Plan, which is submitted annually to the AER for approval.

The numbers of meters requiring changeover are reflective of the age and types of meters in service. As these factors are well documented and tracked, the forecast quantity has a high degree of certainty. The cost of this activity is also well established, with this cost mostly dependent upon three factors:

(a) The forecast cost of new meters - apart from usual cost increases, the average unit cost for a residential meter will continue to increase slightly due to the increasing use of larger capacity meters in homes;

(b) The forecast mix of new and repaired meters - Envestra repairs and recycles meters to the extent possible in order to minimise costs; and

(c) The forecast quantity of meter changes – as expected, the labour cost will fluctuate in proportion to the workload.

The derivation of the forecast cost for PMCs is detailed in Attachment 7-1.

Envestra supplies reports to the AER that detail results of meter testing and compliance. This regulatory oversight provides an additional level of assurance concerning the adequacy of Envestra's operations.

The following table summarises the forecast cost for meter replacement. (The costs are reflective of number of meters, with 2016 requiring much higher replacements than other years – see Attachment 7.1).

Table 7.2: Meter Replacement Forecast Cost, 2013 to 2017 (excl. Cost Escalation and Overheads)

Meter Replacement	2013	2014	2015	2016	2017	Total
Domestic Meters	2.7	5.8	3.7	9.6	2.7	**24.5**
IC Meters	1.1	1.3	1.8	1.4	1.2	**6.7**
Total ($m, real 2011)	**3.8**	**7.1**	**5.5**	**11.0**	**3.9**	**31.2**

This capital expenditure is justifiable because it satisfies the following key element of rule 79(2):

- It complies with a regulatory obligation – Envestra is required to change and test meters in accordance with its Field Life Extension Sampling Plan, as approved by the AER, and in accordance with the Gas Distribution System Code. The forecast is consistent with the requirements of that plan and the Gas Distribution System Code.

7.4.4 Augmentation

Gas flows through the network are continually reviewed and modelled to ensure security of supply to all consumers and that the risk of gas outages is minimised. Network modelling, based on SCADA data and forecast network growth, indicates which parts of the Network require reinforcement or augmentation. The capital expenditure forecast for the next period provides for:

(a) reinforcement of those sections of the network that are vulnerable to gas supply constraints, as well as improvements to reduce the likelihood of outages occurring. A comprehensive plan has been compiled that will deliver a high level of reliability, consistent with both good industry practice and the expectations of consumers;

(b) augmentation to ensure that the network is capable of continuing to satisfy the demand for services, particularly in areas of high growth; and

(c) augmentation to ensure the availability of high pressure gas in a manner that supports the systematic and planned replacement of low pressure mains.

Envestra's Capacity Management Plan provides details of the processes that underpin the augmentation projects, with respective business plans for those projects supplied in Attachment 6-1. The business plans detail the project background, options considered, required timing and associated costs. Table 7.3 provides a summary of the augmentation projects, each of which has its own business plan (as denoted by the project reference in the table).

This capital expenditure is justifiable because it satisfies the following key elements of Rule 79(2):

- It maintains or improves the safety of services – if the above augmentation projects are not carried out, gas pressure to consumers will become comprised. Where insufficient gas pressure is available to fuel appliances (particularly the rapid expansion of instantaneous water heaters), there is a risk of malfunction or flame failure, the consequences of which could be an explosion, or asphyxiation of persons in the vicinity of the appliance;

- It maintains the integrity of services - if the above augmentation projects are not carried out, gas pressure to consumers will become comprised, particularly in times of peak gas demand. This may cause loss of supply to consumers, this being a supply integrity issue; and
- It complies with a regulatory obligation – Envestra is required to maintain a minimum pressure of 1.1 kPa at consumers' meters (Gas Distribution System Code Schedule 1).

The particular reasoning as it relates to each of the above augmentation projects is set out in the business plans attached to this AAI.

Table 7.3: Augmentation Projects (excl. Cost Escalation and Overheads)

Project Reference	Augmentation Projects	$m (real 2011)
V51	Cranbourne	3.0
V52	Lynbrook	0.5
V53	Frankston	0.4
V54	Wodonga	0.4
V55	Mornington Peninsula	0.9
V56	Thomastown	8.0
V57	Plenty Valley	0.6
V58	Trafalgar	0.4
V59	Pakenham	3.3
V60	Morwell	0.5
V61	Sale	0.1
V62	Somerville	0.1
V65	Drouin	0.1
V66	Berwick	0.9
V67	Moe	0.3
V68	Churchill	0.1
V69	Wallan	0.1
V70	Kilmore	0.2
V71	Crib Point	0.1
V72	Echuca	0.2
V73	Eltham	0.1
V74	Healesville	0.7
V75	Ad-hoc Augmentation	3.0
V76	Sale to Mafra Transmission	5.3
V77	Dandenong to Frankston Transmission	0.1
V78	Dandenong to Crib Point Transmission	16.6
V79	Traralgon	0.5
Total $m		**45.8**

7.4.5 Information Technology

A gas distribution business deals with vast amounts of information on a daily basis. The volume of transactions and activity requires periodic investment in information technology (IT), not only to maintain efficiency (i.e. replacement of servers, systems, etc., as they become out-dated or no longer supported by external suppliers) but to satisfy increasing levels of demand for service delivery and knowledge retention/distribution.

The forecast information technology cost includes:

- Critical IT Applications Upgrades and Renewals (Business Case VA203) – to support the periodic upgrade and renewal of Envestra's critical business IT applications such as works management and billing;
- IT Infrastructure Upgrades and Renewals (Business Case VA204) – to support the periodic upgrade of IT Infrastructure and the standardised use of Virtualisation, Storage Area Network and Server Blade technologies;
- Billing Optimisation Project (Business Case VA202) – to define the requirements of a network billing solution to simplify the business billing requirements and provide a cost effective billing solution for the Network;
- Completion of Advanced Asset Management (Business Case VA202) – to upgrade the national network Geographic Information System (GIS) solution used for managing Network assets;
- Field Data Capture Project (Business Case VA202) – to replace paper based processes with electronic work allocation and "in the field" completion of work orders;
- Implementation of a Knowledge Management System (Business Case VA201) – to develop and support a knowledge management solution in order to have well documented processes and information that can be audited and systems to manage documentation; and
- Head Office IT Upgrades and Renewals (Business Case V205) – to maintain head office IT functionality in areas such as IT applications / infrastructure, telephony and data security (with an appropriate amount allocated to the Network).

The following table sets out the forecast capital expenditure over the period. Details of the projects, including costs, are set out in the referenced Business Cases.

Table 7.4: Information Technology Forecast, 2013 to 2017 (excl. Cost Escalation and Overheads)

	2013	2014	2015	2016	2017	Total
Total ($m, real 2011)	**7.0**	**7.2**	**2.8**	**0.1**	**0.7**	**17.8**

This capital expenditure is justifiable because it satisfies the following key elements of rule 79(2):

(a) It maintains integrity of services - without the assistance of information technology, services would not be able to be delivered in an efficient and timely manner. Consequently, the continual upgrade and renewal of critical IT applications and infrastructure, as well as investment in new IT technologies, is vital in order to maintain the ongoing integrity of services; and

(b) It is necessary to comply with regulatory obligations, as without adequate information technology systems, compliance with the Retail Market Procedures would not be possible. These procedures change over time as the market evolves and matures, therefore continual investment in IT system and technologies is necessary to maintain compliance with these regulatory obligations on an ongoing basis.

7.4.6 Residential and I&C Connections

A major driver of new capex is requests from customers to connect to the network. This category of expenditure includes:

- General mains required for growth of the Network; for example, extension of mains for the provision of gas to new customers. New mains projects range from large projects required to provide gas to new housing estates, to small mains extensions in existing gas areas required to connect a single residential customer. The forecast cost is based upon an average length of main (based on a historical average) required to extend the Network on a "per customer" basis, taking into account both new housing estate (greenfields) sites and established suburb (brownfields) sites.

- Inlet services associated with growth of the Network. The inlet service is the pipework that runs from the gas main to the gas meter. These can vary in length and size depending on the gas demand of the customer. The cost per service is affected by the terrain and environmental characteristics of the site being connected (for example, it is easier and cheaper to connect gas to a new home than to an existing home or to an existing building in the CBD); and

- Meters associated with growth of the network. The cost associated with gas meters includes the cost of installation of the meter and gas regulator, and the subsequent commissioning that ensures that gas is supplied in a safe manner in accordance with Envestra's obligations as a gas distributor.

Capex for this category was forecast by applying unit rates for new connections to the connection numbers assumed in the demand forecast. The unit rates and their derivation are set out in attachment 7.1.

This capital expenditure is justifiable because it satisfies rule 79(2) in that the net present value of incremental revenue is expected to exceed the net present value of capex. Envestra's commercial and business processes ensure that capital expenditure for growth/connections is not undertaken unless it is economic. This includes undertaking individual connection analysis where required, with customer contributions requested where the economic test is not met.

7.4.7 Gas Extensions (Business Cases V100 and V103)

The Victorian Government is seeking to extend natural gas across regional Victoria to encourage greater investment in the regions. The Government has made a commitment to invest $100 million over the next few years to support making reticulated natural gas available to homes and businesses in country Victoria under the Regional Development Victoria (RDV) "Energy for the Regions" program[106].

[106] Envestra has previously participated in the Victorian government's schemes for extending gas to regional areas, resulting in gas being made available to various towns including Bairnsdale, St Andrews Beach, Merricks Beach, Paynesville, Hurstbridge, Balnarring and Somers.

The forecast capex allows for extensions of the gas network to 4 regional towns based on a level of government contribution towards the infrastructure. These regions have been selected in consultation with the Victorian Government on the basis that they are included in the Government's list of 12 "priority towns" as part of the "Energy for the Regions" program, and that they are in reasonably close proximity to the existing Envestra Network.

The capital expenditure is justifiable because it satisfies rule 79(2) in that the net present value of the incremental revenue is expected to exceed the net present value of the capex. The level of Government contributions and tariff surcharges are such that the Network extensions will be economic (and as such, only conforming capital expenditure is included in the forecast capital base). The business cases for the network extensions set out the respective NPV calculations.

7.4.8 Other Non Demand

There are numerous other items of capex that do not fall into the aforementioned categories, but which are required to support the delivery of services. The expenditure is set out in detailed business cases (attached to this AAI) that provide detail on the scope of work, derivation of the forecast cost and background pertaining to the requirement for the expenditure.

A brief summary of each business case is set out below. The capital expenditure justification in relation to rule 79(2) is contained in each of the respective business case, which also sets out the scope, timing and costs of each project. Where options are available for project delivery, these are also discussed along with the reasoning provided for the chosen option.

(1) Mains Alterations (Business Case V95)

It is necessary to make provision for the relocation of gas network infrastructure (including the costs of establishing easements where applicable). For example, a risk assessment may conclude that a regulator station may need to be relocated due to the potential safety concerns arising from increasing vehicular traffic. In other situations, it has been found that over the years a change in land use and ownership has resulted in some of Envestra's assets being located within private property (sometimes less than one metre within private property). In such cases, it may be more efficient for Envestra to obtain an easement rather than relocate the infrastructure.

This expenditure is necessary to ensure Envestra has appropriate access to its network assets and to ensure indiscriminate actions by landowners do not result in damage to network assets or put at risk the supply of gas to consumers. The forecast cost has been based on the historical cost of these activities.

(2) Bushfire Risk Mitigation (Business Case V20)

It is planned to install thermal safety devices on new and existing homes in bushfire prone areas so that the gas supply will automatically be shut off in the event of a fire. Retrofitting such devices involves excavation work and isolation of the customer's gas supply while the work is carried out.

(3) Flow Correctors (Business Case V24)

Flow correctors are used on meters for all large customers in order to provide accurate metering data. The current units are at the end of their useful life and hence it is planned to replace them with new flow corrector units that are compatible with current computer operating systems and have the ability to connect to portable computers via current technology interfaces.

(4) City Gate Lightning Protection (Business Case V35)

There are 55 city gate sites in the network that require design and installation of electrical surge protection to be compliant with the requirements of AS 4835 Electrical Hazards on metallic pipelines and AS1768 lightning protection. The project involves each site being reviewed and the appropriate protection installed.

(5) City Gate Pipework Lagging (Business Case VA36)

Thermal lagging (insulation) is installed on pipework at city gate stations between gas heaters and gas regulators. The lagging has reached the end of its useful life and is to be replaced at 30 city gates across the Network.

(6) Refurbishment of Transmission Valves and Pig Traps (Business Case V38)

It is planned to refurbish all transmission pipeline critical isolation valves (line valves) and pig traps on the Network. The majority of these valves and pig traps have been in operation for approximately 40 years since the network conversion from manufactured 'town gas' to natural gas. Most of the line valves are installed in underground pits which are subject to water ingress and a damp environment. These assets are subject to periodic maintenance regimes but after lengthy service are now in need of major refurbishment.

(7) Storm Water Drain Survey (Business Case V40)

Following heavy rains in 2010/11, a number of hazardous incidents occurred during drain clearing operations arising from damage to gas pipes from the drain clearing equipment. Consequently, WorkSafe and ESV requested that the gas distributors undertake an active program to address this hazard. Accordingly, this project seeks to minimise the risk of further incidents by instigating a training program in conjunction with targeted internal inspections of drains and sewers using closed circuit TV technology.

(8) Anode Bed Replacement (Business Case V42)

Anodes are an integral component of the network cathodic protection system. It is planned to replace five existing 'anode beds' which are over 25 years old and approaching the end of their effective design lives.

The replacement of the anode beds is necessary in order to ensure compliance with Australian Standards and to ensure that the integrity of buried steel pipelines in the transmission and distribution systems is maintained. Replacement of the existing anode beds will ensure that there is no drop in the corrosion protection levels for the assets concerned.

(9) Refurbishment of Dandenong to Crib Point Pipeline (Business Case V04)

The Dandenong to Crib Point pipeline (DCP) was originally constructed in 1966 to carry refinery gas from the BP Crib Point refinery to Dandenong. It was subsequently converted to carry natural gas from Dandenong to Crib Point. The DCP was designed and built to the older American Standard USAS B.31.8 code for pressure piping, which does not include improvements contained in in the current Australian Standards.

The DCP is now 45 years old and in order to maintain the ongoing integrity of the 39km pipeline it is planned to carry out:

- pipeline alterations – to enable inline inspection by intelligent pigging;
- intelligent pigging of the pipeline – to assess the pipeline's integrity;
- pipeline refurbishment works – to correct pipeline defects and ensure it is able to operate safely for the remainder of its useful life;
- clearing of easement vegetation – to allow safe and unrestricted access to the pipeline; and
- upgrade of Cathodic Protection (CP) system – to ensure that the pipeline corrosion protection system is able to operate effectively and in accordance with good industry practice.

(10) Water Bath Heater Modifications (Business Case V45)

Water bath heaters are used at city gates to heat the gas to prevent the pipework and gas constituents from freezing as a result of the drop in temperature when gas is regulated down in pressure, thus ensuring an uninterrupted flow of gas.

There are 32 water bath heaters in the Network that require the installation of temperature transducers so that specific heater failure alarms can be sent to the SCADA system. In addition, the installation of temperature transducers will allow temperature of the water to be monitored remotely to determine any action required in response to alarms.

(11) Network Monitoring and Control (Business Case VA06)

This project provides for the establishment of a 24 hour x 7 day (24x7) monitoring and controlling capability to provide an immediate response capability to any alarms that are raised and to arrange the necessary action to remedy the issue, particularly outside of normal business hours.

Swift response and controlling of pressures during an emergency is critical to maintaining system integrity and gas supply to customers.

While other distributors operate their own dedicated 24x7 control rooms for pressure surveillance purpose, Envestra is proposing to outsource this function as this has been assessed as being the most cost efficient option at this time. Most of the project consists of the operating cost associated with outsourcing, but there is a small portion of capex that is associated with set-up costs to enable the contractor to operate.

(12) TD Williamson Equipment (Business Case V08)

T.D. Williamson (TDW) equipment is used in the industry for all drilling and stop off work associated with the construction and maintenance of high pressure steel mains. The existing equipment is over 40 years old and has reached the end of its useful life. Replacement of this equipment commenced in the current period. The forecast cost is for the replacement of the remaining equipment.

(13) Plant and Equipment (Business Case V22)

Expenditure is required annually for the expected costs of replacement of essential tools, plant, equipment and other similar non-reticulation items. The forecast expenditure is based on historical spend and specific requirements for items such as pipe locators, polyethylene pipe tapping equipment, bag tube equipment, temporary regulator sets, leak detectors, pressure data loggers, etc.

(14) Technical Training (Business Case VA23)

This project, which has an opex and capex component, is for the development of interactive online computer based training packages and e-courses to enhance learning and skill development. The project will develop training solutions through interactive online computer based training, and e-courses that use 3D simulations to provide enhanced operator training.

The project also provides for training resources currently held at fixed locations to be supplemented by a mobile training resource that will allow for the consistent delivery of a broad range of skills and competencies across a broad geographic footprint.

(15) Interval Meter Data Management (Business Case VA49)

This project, which has an opex and capex component, is for monthly meter reading of large customers sites and for the management of that data. While this is the continuation of current practice, the work was previously undertaken by AEMO and will now be undertaken by Envestra due to a change in AEMO's contracts with its Metering Data Agent.

The capex is for the initial set-up costs (e.g. hardware, telemetry, etc.), while on-going opex costs pertain to monthly meter read checks, IT support and internal information processing and analysis.

(16) Regional SCADA (Business Case VA02)

This project is for the installation of SCADA (Supervisory Control and Data Acquisition) in regional areas. SCADA capability, when installed at remote locations, provides an early warning system which allows a prompt response to potential supply interruptions. The Melbourne metropolitan area has a SCADA capability throughout the network to control and monitor the 'health' of the systems. This facility does not exist in regional areas.

There are 57 sites in regional parts of the Network that have limited or no SCADA monitoring and/or control. This inability to monitor or operate the system remotely prevents timely responses to emergencies and supply interruptions; for example, if a gas main is damaged by a third party. Having a SCADA capability at these sites along with fringe point monitoring will provide the tools for a more responsive and lower risk operation of regional networks, as well as provide real time data to design engineers for more efficient future network design.

Installation of the SCADA equipment at these regional sites will:

(a) reduce the risk of major supply interruption from an 'over or under pressure' situation caused by failure of key supply regulators or other causes of disruption to supply, thereby improving the safety of services;

(b) form a basis for condition monitoring of key regulator pressures, which in turn will facilitate preventative maintenance schedules; and

(c) provide more accurate, reliable and timely pressure data, from which network capacity models can be validated. Validated network capacity models are essential for optimising timing and scope of system expansion, replacement and reinforcement, this being an important element of maintaining the integrity of services.

(17) Field Asset Refurbishment and Replacement (Business Case V96)

It is necessary to make provision for the replacement or refurbishment of miscellaneous gas network infrastructure that reaches the end of its useful life or is in a condition or location that warrants attention. This expenditure is necessary to ensure Envestra has reliable network assets so as to ensure the integrity of supply to customers. Examples of expenditure include regulator replacement in district regulators and city gate water bath heater coil replacement due to corrosion/pitting.

The forecast has been based on an average of previous years' expenditure.

(18) National Energy Customer Framework (Business Case VA46)

This new legislative framework will require Envestra (and other gas distributors) to implement new systems and processes in order to harmonise the delivery of energy services to customers in Australia. The introduction of the NECF is discussed in chapters 2 and 6 of this AAI.

(19) Easement Vegetation Management (Business Case VA33)

Envestra plans to implement a vegetation management program to initially clear mature and over grown vegetation along transmission pipeline easements and then to monitor and clear these pipeline corridors on a routine basis (3 to 5 year program) to ensure they remain free of significant vegetation growth. The program will:

- ensure line of sight of marker posts is maintained along pipeline corridors;
- ensure access to pipeline corridors is provided for pipeline operation, maintenance and emergency activities;
- mitigate the risk of tree root growth damaging pipeline coating; and
- mitigate future liabilities associated with vegetation clearance and net gain obligations.

The following table summarises the total cost in this category (Other Non Demand) of capex.

Table 7.5: Other Non-Demand Capex, 2013 to 2017 (excl. Cost Escalation and Overheads)

	2013	2014	2015	2016	2017	Total
Total ($m, real 2011)	**13.1**	**14.0**	**9.3**	**6.0**	**5.7**	**48.0**

7.5 Overheads

Overhead costs are applied to capital expenditure in order to recover general business overheads that are not accounted for in direct capital expenditure estimates. These overhead costs generally include costs associated with operations management and administration, network planning and system design, procurement and fleet, technical assurance, network engineering and other support costs (e.g. finance, IT, HR, HSE and insurance).

Overhead uplift rates are applied to the direct costs proposed in Envestra's capital expenditure program.

An analysis of the actual overheads incurred over the past four years has been undertaken and reveals that an average overhead rate of around 20% is required to recover these costs. Actual results shown in Envestra's audited Regulatory Accounting Statements for the network for the years 2008 to 2010 show the level of overheads incurred in those years. The resulting overhead percentages for those years range from 17.5% to 21.3% as shown in the following table.

Table 7.6: Overheads History from the Regulatory Accounting Statements, 2008 to 2010

	2008	2009	2010
Overheads ($m, 2011)	9.3	9.4	10.2
Overhead %	17.5	21.3	19.0

Envestra believes that a 20% overhead rate will continue to be appropriate as a 'baseline' for general overheads to apply over the 2013 to 2017 Access Arrangement period, but that this should be combined with a more conservative overhead rate of 10% for the mains replacement and augmentation program. The lower rate of 10% recognises this expanded capital expenditure program and the nature of fixed versus variable overheads.

Fixed overheads, as the term suggests, generally do not increase as the capital expenditure program increases, while variable overheads do increase (or decrease) as the size of the capital expenditure program expands (or contracts). The forecast overhead rate of 10% on mains replacement and augmentation is to account for the increase in variable overheads resulting from the materially expanded expenditure program.

The above approach results in an average overhead rate of 15% over the forecast period.

This approach was applied by Envestra and accepted by the AER in its Final Decision in respect of Envestra's South Australian distribution network. In that review, Envestra provided the AER with expert advice from Parsons Brinckerhoff Australia Pty Limited (PB) which concluded that:

> "*PB has considered the regulatory approach to overheads, the way in which Envestra has calculated overhead and has undertaken a high-level benchmark of current and forecast overheads. We conclude that the approach taken by Envestra is a reasonable approach to forecast overheads for the 2011/12 to 2015/16 period, and consider that the outcome (an average overhead rate of approximately 15% of forecast expenditure) is a reasonable estimate of overheads likely to be incurred in the delivery of the expanded capital program*"[107].

[107] Parsons Brinckerhoff Australia Pty Limited March 2011, "Level of Overheads", pg. 8

The AER approved an average overhead rate of 15% in its Final Decision in respect of Envestra's South Australian distribution network, which is consistent with that proposed to apply in Victoria.

In conclusion, Envestra has forecast overheads taking into consideration:

(a) historical overhead costs;

(b) the fixed and variable nature of overheads;

(c) the change in the level of capital expenditure in the forecast period compared to the current period;

(d) expert advice provided by PB; and

(e) approaches previously accepted by the AER.

On this basis Envestra submits that this approach to forecasting overheads provides an estimate that represents the best estimate arrived at on a reasonable basis as required by the NGR.

7.6 Escalators

The forecast changes in labour, materials and construction costs have been applied to forecast capital expenditure over the 2013 to 2017 Access Arrangement period. As explained in section 6.9 of this AAI, Envestra engaged BIS Shrapnel to provide its views on expected changes in a range of generic input costs relevant to providing operating and capital expenditure. These forecasts are set out in following table.

Table 7.7: Labour and Materials Escalators, 2012 to 2017

Real adjusted for Productivity	2012	2013	2014	2015	2016	2017
EGW Lab	1.6%	3.0%	6.6%	4.1%	1.0%	-0.1%
General Lab	1.9%	3.0%	6.8%	3.6%	0.7%	0.6%
N/W Materials	-2.7%	2.7%	11.5%	4.4%	-2.5%	4.0%
General Materials	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Construction (capex only)	3.9%	2.9%	2.8%	2.2%	0.8%	1.8%

7.7 Expert Review of Capital Expenditure

Envestra engaged PB Associates to review elements of the forecast capital expenditure, particularly key business cases. PB reviewed those business cases, including the underlying assumptions and parameters, options considered, proposed cost and so on, for compliance with the NGR. This review was used as an input to ensure that the businesses cases complied with the all aspects of the regulatory framework.

7.8 Summary

Envestra's forecast of capital expenditure for the 2013 to 2017 Access Arrangement period allows the business to provide reference services in a manner that is prudent, efficient, safe and reliable (as required by the relevant regulatory obligations governing capital expenditure). Where possible, Envestra has relied upon historical information and costs to derive reasonable forecasts. Historical costs have been deemed to be efficient given the strong commercial and regulatory incentives governing expenditure.

In forecasting costs, consideration has also needed to be given to the labour market in which Envestra operates, particularly the tightening labour market arising from the large number of infrastructure projects, particularly in the mining and upstream gas industry (see chapter 2). As labour costs comprise a significant portion of capital expenditure, it is acknowledged that the cost of capital projects going forward will increase.

For the various categories of expenditure and within each business case for expenditure, Envestra has described where appropriate/relevant how the expenditure:

- is prudent, efficient and consistent with good industry practice; and/or
- is necessary to maintain or improve the safety, integrity or reliability of services; and/or
- meets the economic test for inclusion into the regulatory asset base.

On this basis, Envestra believes that its capital expenditure is consistent with the requirements of the NGR, including rule 79. The resultant capital expenditure is summarised in the following table.

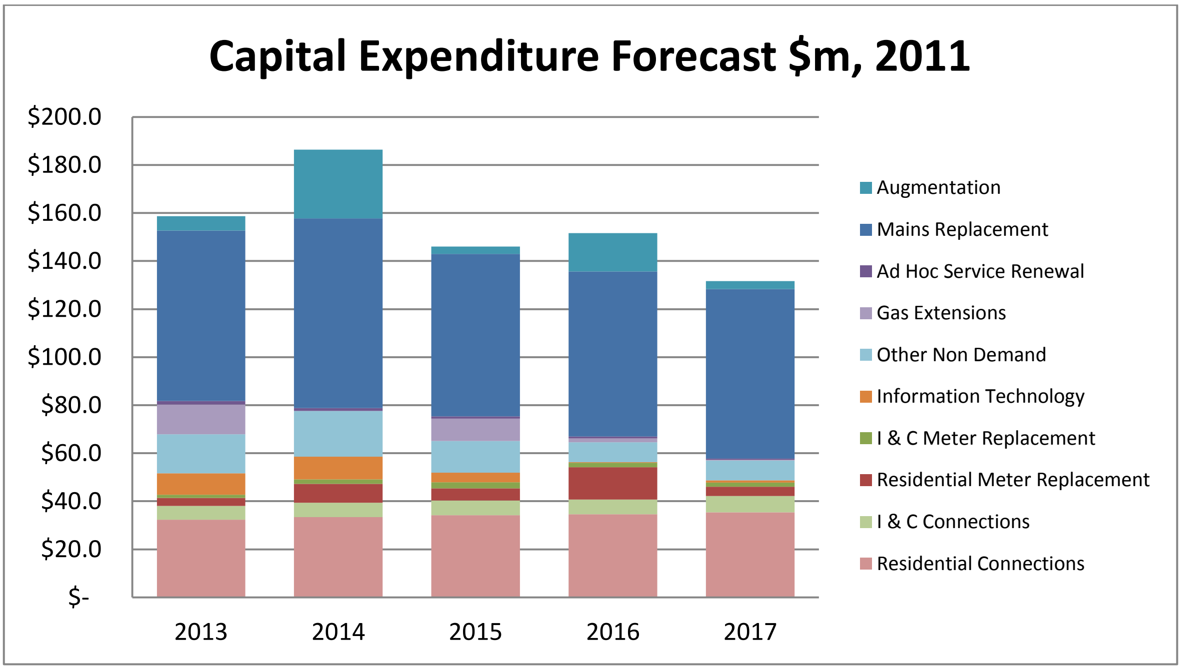
Table 7.8: Forecast Capital expenditure, 2013 to 2017

Capital Expenditure $m (real 2011)	2013	2014	2015	2016	2017	Total
Mains Replacement	70.9	78.9	67.6	68.7	70.5	**356.7**
Ad Hoc Service Renewal	1.4	1.2	1.0	0.8	0.5	**5.0**
Residential Meter Replacement	3.4	7.8	5.2	13.4	4.0	**33.7**
I & C Meter Replacement	1.3	1.8	2.5	1.9	1.7	**9.2**
Augmentation	6.0	28.7	3.0	16.0	3.5	**57.2**
Information Technology	8.9	9.5	3.9	0.2	0.9	**23.5**
Residential Connections	32.4	33.4	34.2	34.6	35.4	**170.0**
I & C Connections	5.7	6.0	6.0	6.2	6.7	**30.7**
Gas Extensions	12.4	0.0	9.3	1.6	0.3	**23.6**
Other Non Demand	16.1	19.0	13.2	8.3	8.2	**64.9**
Total Capex	**158.6**	**186.4**	**146.0**	**151.6**	**131.7**	**774.4**

The composition of capital expenditure over the 2013 to 2017 Access Arrangement period is shown in the below figure. This shows that Envestra's mains replacement program and augmentation works accounts for the majority of the increase in the capital expenditure program. With regard to mains replacement, the program is scheduled to be completed in 2020/21, with the amount of replacement tapering off in the latter years of the program. Hence the amount of capital expenditure in the subsequent access arrangement period is expected to be significantly lower.

Spreadsheet models showing how the capex forecasts have been derived are provided in attachment 7.6 to this AAI.

Figure 7.1: Capital Expenditure Forecast 2013 to 2017



8. Capital Base

8.1 Introduction

This chapter shows how the value of Envestra's capital base is adjusted for actual information over the 2008 to 2012 Access Arrangement period. This chapter then adjusts the capital base for forecast information over the 2013 to 2017 Access Arrangement period.

8.1.1 Requirements of the National Gas Rules

The requirements for establishing the opening capital base as at 1 January 2013 are set out in Rule 77 of the National Gas Rules (NGR). Rule 77(2) of the NGR states that:

> *"If an access arrangement period follows immediately on the conclusion of a preceding access arrangement period, the opening capital base for the later access arrangement period is to be:*
>
> *(a) The opening capital base as at the commencement of the earlier access arrangement period (adjusted for any difference between estimated and actual capital expenditure included in that opening capital base); plus:*
>
> *(b) conforming capital expenditure made, or to be made, during the earlier access arrangement period; plus:*
>
> *(c) any amounts to be added to the capital base under rule 82, 84 or 86; less:*
>
> *(d) depreciation over the earlier access arrangement period (to be calculated in accordance with any relevant provisions of the access arrangement governing the calculation of depreciation for the purpose of establishing the opening capital base);*
>
> *(e) redundant assets identified during the course of the earlier access arrangement period; and*
>
> *(f) the value of pipeline assets disposed of during the earlier access arrangement period."*

Rules 82, 84 or 86 relate to capital contributions, speculative capital expenditure and the re-use of redundant assets respectively. Envestra has not in the past, nor does it propose to in the future, include any such amounts in its capital base. These parts of the NGR have therefore not been considered further.

The requirements regarding conforming capital expenditure have been considered in chapter 7 of this AAI.

The requirements for establishing the closing capital base as at 31 December 2017 are set out in rule 78 of the NGR. Rule 78 of the NGR states that:

> *"The projected capital base for a particular period is:*
>
> *(a) The opening capital base; plus:*

> (b) *Forecast conforming capital expenditure for the period; less*
>
> (c) *Forecast depreciation for the period; and*
>
> (d) *The forecast value of pipeline assets to be disposed of in the course of the period."*

Rule 89 of sets out the depreciation criteria, which requires that a depreciation schedule should be designed:

(a) so that reference tariffs will vary, over time, in a way that promotes efficient growth in the market for reference services; and

(b) so that each asset or group of assets is depreciated over the economic life of that asset or group of assets; and

(c) so as to allow, as far as reasonably practicable, for adjustment reflecting changes in the expected economic life of a particular asset, or a particular group of assets; and

(d) so that (subject to the rules about capital redundancy), an asset is depreciated only once (i.e. that the amount by which the asset is depreciated over its economic life does not exceed the value of the asset at the time of its inclusion in the capital base (adjusted, if the accounting method approved by the AER permits, for inflation)); and

(e) so as to allow for the service provider's reasonable needs for cash flow to meet financing, non-capital and other costs.

Finally, Rule 90 states that in calculating depreciation for rolling forward the capital base from one access arrangement period to the next, any provisions governing the calculation of depreciation must resolve whether depreciation of the capital base is to be based on forecast or actual depreciation.

8.2 Regulatory Asset Base as at 1 January 2013

This section discusses how Envestra has adjusted the capital base over the 2008 to 2012 Access Arrangement period to reflect actual information over that period.

8.2.1 Opening Capital Base as at 1 January 2008

The opening capital base as at 1 January 2008 is $853.5 million ($ nominal), which has been derived by:

- taking from the revenue model set by the Essential Services Commission of Victoria (ESCV) the opening capital base as at 1 January 2007 of $794.3 million ($ July 2006), which reflects the latest actual information used by the model;
- add the actual capital expenditure (capex) in 2007 of $46.0 million ($ July 2006);
- less the forecast depreciation set by the ESCV of $30.6 million (in $ July 2006), as set out in the ESCV revenue model; to
- derive a closing capital based as at 31 December 2007 of $809.7 million (in $ July 2006).

The actual closing capital base of $809.7 million is slightly less than the forecast closing capital base of $812.9 million ($ July 2006) set by the ESCV. This difference is explained by the difference between the forecast of net capex used by the revenue model for 2007 of $49.2 million (in $ July 2006) and actual capex of $46.0 million.

This 31 December 2007 closing capital base of $809.7 million is added to the actual capital base for the Bairnsdale and Paynesville networks of $12.0 million, resulting in a final closing capital base as at 31 December 2007 of $821.7 million (in $ July 2006). The ESCV accepted the Bairnsdale and Paynesville networks to be rolled into the capital base in its Final Decision for the 2008 to 2012 Access Arrangement period.

The 31 December 2007 closing capital base of $821.7 million (in $ July 2006) is then adjusted for actual inflation to derive the opening capital base value as at 1 January 2008 of $853.9 million in nominal dollar terms.

8.2.2 Capital Base for the 2008 to 2012 Access Arrangement period

Envestra has adjusted (or "rolled forward") the capital base as at 1 January 2008 to derive a closing capital base as at 31 December 2012 (in $ July 2006). Envestra has adjusted the opening capital base by adding actual net capex less forecast depreciation plus inflation in each year of the 2008 to 2012 Access Arrangement period. The inputs used by Envestra to roll forward the capital base are described below.

8.2.2.1 Capital Expenditure

Conforming capex was calculated by deducting capital contributions from gross capex. The nominal conforming capex was converted to July 2006 dollar terms for the purposes of rolling forward the capital base consistent with the approach taken by the ESCV to forecast the capital base for the 2008 to 2012 Access Arrangement period. Envestra has used its best estimate of capex for 2012, which will be updated in response to the AER Draft Decision.

Table 8.1: Conforming Capex, 2008 to 2012

$m Nominal	2008	2009	2010	2011	2012
Gross Capital Expenditure	50.8	43.6	55.1	76.8	97.2
Capital Contributions	1.7	0.7	1.7	4.6	1.9
Conforming Net Capital Expenditure	49.0	42.9	53.4	71.2	95.3

Envestra considers that its actual capex in the 2008 to 2012 Access Arrangement period is prudent, efficient and in accordance with good industry practice to achieve the lowest sustainable costs. As discussed in chapter 7, Envestra has strict governance and cost management protocols in place to ensure that actual capex is prudent and efficient. This includes:

(a) preparation of robust business plans and procedures governing asset management strategies and expenditure, particularly Envestra's Asset Management Plan and all subordinate plans;

(b) application of rigorous analysis, including an assessment of various options, to ensure that the capex provides the most prudent and cost effective long term option for consumers;

(c) outsourcing to the APA Group, who is able to achieve lower cost outcomes due to its ability to access considerable economies of scale, scope and know-how that is not otherwise available to Envestra;

(d) strict cost management protocols under the 2007 Operating and Management Agreement between Envestra and APA, including the processes around setting of annual budgets, the ongoing monitoring of actual performance against the budget and regular audits of incurred expenditure; and

(e) existence of strong commercial and regulatory incentives to achieve lowest sustainable costs.

8.2.2.2 Regulatory Depreciation

Regulatory depreciation for the 2008 to 2012 Access Arrangement period has been set equal to the forecast of regulatory depreciation made by the ESCV (see table 8.2).

Table 8.2: Regulatory Depreciation for Second Access Arrangement period

Depreciation $m July 2006	2008	2009	2010	2011	2012
ESCV Forecast	28.5	31.5	34.3	36.6	38.2

8.2.2.3 Redundant Assets

Rule 85 of the NGR states that an access arrangement may include a mechanism to ensure that assets that cease to contribute in any way to the delivery of pipeline services (redundant assets) are removed from the capital base. Envestra is not forecasting there to be any redundant assets over the 2008 to 2012 Access Arrangement period.

That aside, section 7.1(e)(2)(E) of the 2008 to 2012 Access Arrangement contains a fixed principle that does not allow the capital base to be adjusted for any assets that may become redundant. This fixed principle applies for a period of thirty years from 1 January 2003 to 31 December 2032 and is also contained in Fixed Principle A part (c) of section 4.7 of the proposed 2013 to 2017 Access Arrangement.

8.2.2.4 Inflation

Envestra has applied inflation in a manner that is consistent with that applied by the ESCV in past regulatory decisions.

8.2.2.5 Opening Asset Values as at 1 January 2013

Using the inputs outlined above, the capital base has been rolled forward to the end of the 2008 to 2012 Access Arrangement period. Table 8.3 shows that this results in an opening capital base at the start of the 2013 to 2017 Access Arrangement period (i.e. as at 1 January 2013) of $926.4 million (in $ July 2006).

Table 8.3: Roll-forward of the Capital Base, 2008 to 2012

$m July 2006	2008	2009	2010	2011	2012
Opening Capital Base	822.1	839.9	847.0	860.1	885.0
Less Depreciation	28.5	31.5	34.3	36.6	38.2
Plus Conforming Capital Expenditure	46.3	38.6	47.4	61.5	79.6
Closing Value	**839.9**	**847.0**	**860.1**	**885.0**	**926.4**

As the AER's Post Tax Revenue Model (PTRM) is a nominal model, the capital base as at 31 December 2012 was converted to nominal terms by dividing the estimate of March 2012 CPI by the September 2005 CPI (which was used by the ESCV to express terms in $ July 2006). Table 8.4 shows the closing capital base as at 31 December 2012 by asset category in nominal dollar terms, which breakdown is required by the PTRM.

Table 8.4: Capital Base by Asset Category as at 31 December 2012 ($m Nominal)

Asset	$m
Mains and Services	981.2
Meters	98.8
Land & Buildings	8.8
SCADA	0.8
Computer Equipment	0.7
Other Assets	26.0
Total	**1,116.3**

8.3 Forecast Capital Base in the 2013 to 2017 Access Arrangement period

The forecast capital base in the 2013 to 2017 Access Arrangement period has been determined by adjusting the closing value as at 31 December 2012 for forecast capex, depreciation and inflation. Each of these matters is addressed in this section.

8.3.1 Capital Expenditure

The forecast capex for the 2013 to 2017 Access Arrangement period is summarised in table 8.5. For the purpose of rolling forward the capital base, capex has been allocated to the categories set out in table 8.5, which are consistent with the asset categories used by the ESCV in previous Access Arrangement reviews[108]. Capital expenditure is also expressed in end of year terms, as required by the PTRM (and for this reason differs from that set out in chapter 7).

108 Envestra notes that there is an additional category called "Equity Raising Costs", which amount has been determined and treated in a manner that is consistent with that set out in the AER Post Tax Revenue Model Handbook – Amendment, December 2010, pages 19-21.

Table 8.5: Forecast Capex, 2013 to 2017 ($m Nominal)

Capital Expenditure $m Nominal	2013	2014	2015	2016	2017	Total
Mains and Services	128.0	151.8	125.4	136.0	126.5	**667.7**
Meters	10.4	16.3	14.8	23.8	13.5	**78.7**
Land & Buildings	-	-	-	-	-	**0.0**
SCADA	1.7	1.8	1.8	1.9	1.9	**9.2**
Computer Equipment	9.4	10.2	4.3	0.2	1.1	**25.2**
Other Assets	15.2	18.7	12.7	7.6	7.6	**61.8**
Equity Raising Costs	2.4	0	0	0	0	**2.6**
Total Capex	**167.2**	**198.8**	**159.1**	**169.4**	**150.6**	**845.0**

8.3.2 Forecast Depreciation

Envestra has continued to use a straight-line approach to calculate forecast depreciation based on defined asset lives. A straight-line approach ensures that:

- each asset is depreciated over the reasonably expected useful life of that asset;
- each asset is depreciated only once; and
- reference tariffs vary in a way that promotes the efficient growth for reference services.

The straight-line approach also has the advantage of being easily understood, transparent; and capable of being replicated on an ongoing basis.

In terms of the economic lives used to calculate depreciation, Envestra has historically used the asset lives shown in table 8.6.

Table 8.6: Historic Asset Lives for Network Assets

Asset Categories	EUL (years)
Mains and Services	60
Meters	20
Other Assets	15
SCADA	10
Buildings	50
Computer Equipment	5

Envestra has reviewed the above asset lives and has determined that the asset life used for meters needs to be amended. Envestra proposes to align the current asset life of 20 years for meters with the 15 year life used for Envestra's other networks.
In 2006, a new Australian Standard (AS 4944) called "Gas Meters – In Service Compliance Testing" was published with the following key features:

- all domestic meters installed prior to the revised Australian Standard are deemed to have a 15 year service life; and

- under the revised Australian Standard, meters are obliged to undergo a compliance test within 3 to 5 years of installation to establish an initial service life. Depending on the results of testing, a service life of 5, 10, 15 and 18 years can be deemed for that meter family.

In consideration of the above, a useful life of 15 years is considered both reasonable and appropriate for meter expenditure and is also consistent with that recently approved by the AER in respect of Envestra's South Australian and Queensland networks.

The PTRM requires that the remaining life of assets in service at the start of the regulatory period be determined. This is to determine the extent of depreciation, on average, that is required to be applied to the opening capital base over the 2013 to 2017 Access Arrangement period. Envestra has applied an approach to determining remaining asset lives that is consistent with that used by the AER.

A summary of the existing and proposed standard asset lives in respect of new capex and the remaining life of existing assets is set out in table 8.7.

Table 8.7: Summary of Standard and Remaining Asset Lives

Asset Category	Original Useful Life	Revised Useful Life	Remaining Life
Mains and Services	60	60	39.7
Meters	20	15	7.8
Land & Buildings	15	15	21.0
SCADA	10	10	7.2
Computer Equipment	50	50	2.9
Other Assets	5	5	11.0
Equity Raising Cost			54.8

Based on the above, the forecast deprecation over the 2013 to 2017 Access Arrangement period is set out in table 8.8.

Table 8.8: Regulatory Depreciation, 2013 to 2017

Depreciation $m (nominal)	2013	2014	2015	2016	2017
Forecast Depreciation	41.5	48.8	57.5	64.0	70.4

8.3.3 Forecast Inflation

Envestra has applied a forecast inflation rate of 2.50% for each year of the 2013 to 2017 Access Arrangement period, the basis for which is explained in chapter 9 of this Access Arrangement Information.

8.3.4 Forecast Roll Forward of the Capital Base

The forecast capital base over the 2013 to 2017 Access Arrangement period, taking into account the opening capital base, forecast capex, inflation and depreciation is set out in table 8.9. This shows a closing capital base of $1,886.1 million as at 31 December 2017 in nominal dollar terms.

Table 8.9: Roll-forward of the Capital Base, 2013 to 2017

$m Nominal	2013	2014	2015	2016	2017
Opening Capital Base	1,116.3	1,275.1	1,463.2	1,606.3	1,757.3
Plus Conforming Capital Expenditure	172.4	205.0	164.1	174.8	155.3
Less Depreciation	41.5	48.8	57.5	64.0	70.4
Inflation Adjustment	27.9	31.9	36.6	40.2	43.9
Closing Value	**1,275.1**	**1,463.2**	**1,606.3**	**1,757.3**	**1,886.1**

8.3.5 Opening Asset Base as at 1 January 2018

Pursuant to rule 90(2), Envestra nominates that actual depreciation be used to adjust the capital base over the 2013 to 2017 Access Arrangement period in order to determining the opening capital base as at 1 January 2018. The application of actual depreciation strengthens the incentive on Envestra to incur prudent and efficient capital expenditure that is consistent with good industry practice.

8.4 Summary

Envestra has determined that the capital base on 1 January 2013 will be $1,116.3 million and is forecast to be $1,886.1 million at 31 December 2017 in nominal dollar terms (see table 8.10).

Table 8.10: Closing Capital Base as at 31 December 2017

	$m
Capital Base as at 31 December 2017 (nominal)	$1,886.1
Capital Base as at 31 December 2017 (real $2012)	$1,667.0

9. Rate of Return

9.1 Introduction

This chapter sets out the rate of return to apply for the 2013 to 2017 Access Arrangement period. Under the National Gas Rules, the rate of return is applied to the projected capital base at the beginning of each year of the access arrangement period for the purposes of determining the return on that projected capital base. That return forms part of the building blocks from which total revenue is calculated (see chapter 12).

Envestra submits that the rate of return that best meets the criteria in the National Gas Law ('NGL') and National Gas Rules ('NGR') for determining total revenue and reference tariffs is 9.06% (nominal post-tax).

This rate of return has, in accordance with the requirements of rule 87 of the NGR and section 24(5) of the National Gas Law, been established as a weighted average of a cost of equity[109] (10.8%) and a cost of debt (7.9%) that are commensurate with prevailing conditions in the market for funds; the risks involved in providing reference services; and the regulatory and commercial risks involved in providing those reference services.

The rate of return on equity of 10.8% has been derived using the Capital Asset Pricing Model. In arriving at this return on equity, Envestra took into consideration a number of alternative estimates of the cost of equity derived from other well accepted financial models as an "output check" to ensure the proposed rate of return on equity complied with the requirements of rule 87(1).

The remainder of this chapter provides the information supporting the derivation of the proposed rate of return and is structured as follows:

- Section 9.2 provides an analysis of the regulatory framework applicable to determining the rate of return for covered natural gas distribution systems;
- Section 9.3 describes the difficulties which arise in using the standard AER methodology historically applied to determine the rate of return;
- Section 9.4 discusses the approach taken by Envestra to determine the rate of return;
- Sections 9.5 to 9.6 provides the estimated cost of equity;
- Section 9.7 provides the estimated cost of debt;
- Section 9.8 provides the parameter values for gearing, inflation and debt raising costs;
- Section 9.9 outlines the rate of return proposed by Envestra for the 2013 to 2017 Access Arrangement period.

[109] The terms 'cost of equity', 'rate of return on equity' and 'return on equity' are used interchangeably

9.2 Requirements of the National Gas Rules

The relevant rules are 74 and 87. Rule 74 provides:

> *"1) Information in the nature of a forecast or estimate must be supported by a statement of the basis of the forecast or estimate.*
>
> *2) A forecast or estimate:*
>
> *(a) must be arrived at on a reasonable basis; and*
>
> *(b) must represent the best forecast or estimate possible in the circumstances."*

Rule 87 provides:

> *"1) The rate of return on capital is to be commensurate with prevailing conditions in the market for funds and the risks involved in providing reference services.*
>
> *(2) In determining a rate of return on capital:*
>
> *(a) it will be assumed that the service provider:*
>
> *(i) meets benchmark levels of efficiency; and*
>
> *(ii) uses a financing structure that meets benchmark standards as to gearing and other financial parameters for a going concern and reflects in other respects best practice; and*
>
> *(b) a well accepted approach that incorporates the cost of equity and debt, such as the Weighted Average Cost of Capital, is to be used; and a well accepted financial model, such as the Capital Asset Pricing Model, is to be used."*

9.2.1 Interpretation of Rule 87(1)

Rule 87(1) requires that the rate of return meet two criteria. The return must be:

(a) commensurate with prevailing conditions in the market for funds; and

(b) commensurate with the risks involved in providing reference services.

It is clear that the NGR do not contemplate the mechanistic application of a financial model to the determination of a rate of return. If it did then rule 87 would simply direct the application of such a model and there would be no reference to the more general factors of the return being commensurate with funding and reference service risks.

Rather, the employment of any model requires the exercise of judgement to ensure that the overriding criteria of reflecting prevailing conditions in the market for funds and the risks involved in providing the reference services are achieved.

9.2.2 Interpretation of Rule 87(2)

Rule 87(2)(a)(i) provides that in determining a rate of return on capital it is to be assumed the service provider meets benchmark levels of efficiency. While there will be elements of judgement and analysis in determining what are the benchmark levels of efficiency, it is clear that the regulator must conduct its analysis on the basis that the service provider meets such benchmarks.

Rule 87(2)(a)(ii) requires it to be assumed that the service provider uses a financing structure that meets benchmark standards as to gearing and other financial parameters for a going concern and reflects in other respects best practice. As with rule 87(2)(a)(i) there are elements of judgement and analysis in determining what are the benchmarks and what reflects best practice, but there is no discretion to depart from these assumptions in assessing the rate of return.

It appears that rule 87(2)(a)(ii), in its reference to gearing and financial parameters, is concerned with issues of the efficiency of a service provider's financing structure. Rule 87(2)(a)(i) would therefore appear to be concerned with the efficiency with which the service provider raises and utilises capital, which the service provider is assumed to do at benchmark levels.

9.2.3 Well Accepted Financial Model

Rule 87(2) requires the rate of return on capital to be determined by the use of a well accepted financial model, such as the Capital Asset Pricing Model.

"Well-accepted" is not defined in the NGR. However as the intent of the NGR is to set a rate of return commensurate with the prevailing (or real-world) market for funds, Envestra considers that the natural meaning of well-accepted is "well-accepted" by those persons who undertake the task of assessing the cost of funds in capital markets.

The term Capital Asset Pricing Model is not defined and Envestra notes that there are many variants of the Capital Asset Pricing Model. The original Capital Asset Pricing Model was the model developed by William Sharpe and John Lintner. This "Sharpe-Lintner CAPM" was further developed by Fischer Black to make the original borrowing assumptions more reflective of reality and the outturn cost of equity estimates more empirically robust (i.e. Black CAPM).

Envestra submits that when read together rules 87(1) and 87(2) require the Capital Asset Pricing Model (or some other well-accepted financial model) to be applied with the necessary elements of judgement to ensure that the rate of return derived is commensurate with prevailing conditions in the market for funds and the risks involved in providing reference services. If the intention of the NGR is that one simply applied a well-accepted financial model and accepted the results without any further checks of whether those results reflect prevailing conditions in the market for funds and the risks involved in providing the reference services, rule 87(1) would be unnecessary.

Of its nature, rule 87(2) is subordinate to rule 87(1), as rule 87(1) sets out the general test and rule 87(2) the methodology applied. That is, rule 87(2) must be applied in a way which gives effect to rule 87(1).

If the contrary were intended, that is that the Regulator just applies the model, approach and benchmarks referred to in rule 87(2) in a mechanistic way without regard to whether the output meets the relevant criteria, then rule 87(1) would not be required (as it would not perform any meaningful role in the determination of the rate of return).

Envestra considers that the requirement to apply rule 87(2) with discretion means that the "well-accepted financial model" must be applied:

(1) having regard to the issues identified with the application of the model (for example its reliability and the selection of input parameters); and

(2) having regard to the manner in which practitioners apply the model, given that the behaviour of these persons actually in the market place is clearly highly relevant to the actual cost of funds in the market place and the reliability of the model estimates.

In respect of the above points Envestra notes that good valuation practice requires the use of more than one valuation methodology. This is reflected in ASIC's Regulatory Guideline 111 "Content of Expert Reports" which provides "*We consider that an expert should, when possible, use more than one valuation methodology. We consider that this reduces the risk that the expert's opinion is distorted by its choice of methodology. We also consider that an expert should compare the figures derived from using the different methodologies and comment on any differences*."

ASIC Regulatory Guideline 111 is a 'best practice' guideline for corporate valuations professionals performing company valuations in the context of market-based transactions, such as acquisitions. Valuing businesses using either the dividend growth model or the discounted cash flow methodology is analogous to deriving the rate of return for regulatory purposes insofar as it requires a reasonable point estimate of a business's efficient cost of capital in prevailing market conditions. Therefore, the requirements and recommendations contained in ASIC Regulatory Guideline 111 are relevant considerations in the task of estimating the rate of return in accordance with the NGR.

Furthermore, the desirability of this approach was also acknowledged by the Australian Competition Tribunal in *Application by Telstra Corporation Limited ABN 33 051 775 556 [2010] ACompT* where the Tribunal stated, at paragraphs 477 to 478:

> *"477 Both the ACCC and Telstra have employed a variety of techniques to estimate the equity beta. Each of these techniques is capable of generating a value for the equity beta. The Tribunal supports this approach. This is because the value of WACC requires an exercise of some balancing and judgment. It applies equally to the ultimate WACC value as it does to the individual parameter values - like the equity beta.*
>
> *478 For that reason employing a variety of techniques provides a firmer foundation from which to make those judgments. It also allows parameter values derived under one technique to be effectively tested for its robustness against another technique. In this way the process of balancing and the exercise of judgment can be more refined*".

Therefore, best practice dictates that the rate of return on equity from the CAPM[110] and the estimated cost of debt be tested for compliance with the NGR and applicability to prevailing capital market conditions. This can be done by following an assessment of market conditions and by comparing against the results produced by other methodologies to ensure consistency with rule 87(1).

[110] Sharpe-Linter Capital Asset Pricing Model ('CAPM')

9.3 Deficiencies in the Standard AER Method for Determining the Cost of Equity

The AER's standard method for deriving the required cost of equity at the current time is to add a 4.8% equity premium (i.e. 0.8 equity beta multiplied by the 6.0% market risk premium from the AER's most recent gas and electricity distribution decisions) to the short-term average nominal yield observed on 10-year Commonwealth Government Bonds (or 'CGS')[111]. This approach does not provide a return on equity that complies with rule 87 at all times and in all circumstances.

Figure 9.1 shows how the yield on 10-year Commonwealth Government Bonds has moved between 2002 and 2012. During the last two major financial crises (the GFC in 2008 and the subsequent European sovereign debt crisis in the second half of 2011) the yield on Australian 10-year Commonwealth Government Bonds has fallen precipitously. The fall in yield (or risk free rate in the CAPM context) is reflected in the standard AER methodology as a reduction in the return to equity. A lower return on equity is not consistent with how a rational risk averse equity investor would be expected to react in the face of such uncertainty and escalating capital market volatility (i.e. to lower their risk compensation requirements).

Rather, the reduction in return on equity as forecast by the standard AER approach is driven solely by the fall in Commonwealth Government Bond yields which has been driven by increased investor risk aversion as a result of the ratings downgrades of the Australian banks[112], foreign banks, Basel III[113] and sovereign debt problems in Europe and the United States (see chapter 2). This has resulted in greater demand for Australian government bonds which has depressed the observed yield. This significant change in the market did not escape the view of the Reserve Bank of Australia when it pointed out that the yield on 10 year Australian Government Bonds is tracking at historically low levels (50 year lows):

> *Strong demand, particularly from offshore investors for relatively safe assets in the uncertain global climate has been apparent in the demand for Australian Government bonds over the past couple of months. (As at the end of September, non-residents were estimated to be holding around 75 per cent of Commonwealth Government securities (CGS) on issue.) The yield on 10-year CGS fell to 3.67 per cent in mid January, its lowest level in 50 years (Graph 4.3).* [114]

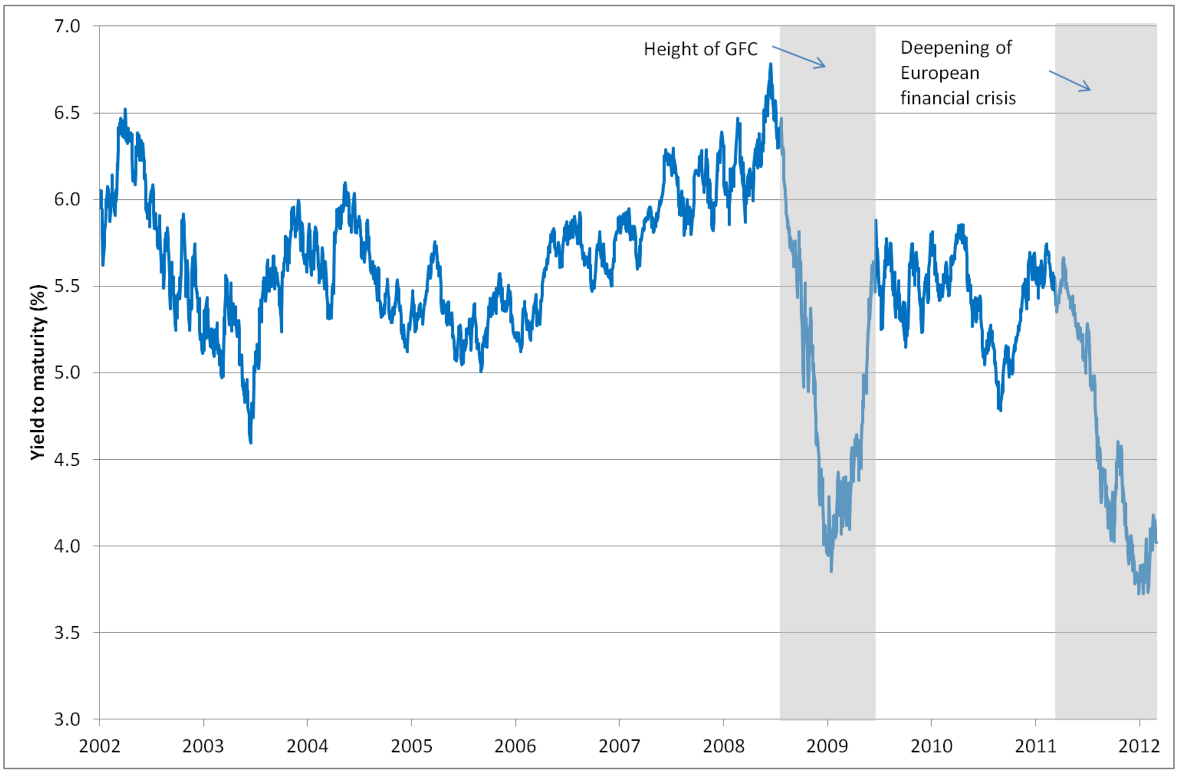
[111] Which is used as the proxy for the risk free rate

[112] Standard & Poor's cut the long-term ratings on Australia and New Zealand Banking Group, Commonwealth Bank of Australia, National Australia Bank and Westpac Banking Corp by one notch from AA to AA-, 1 December 2011

[113] Basel III is a set of banking regulations designed to improve the liquidity and capital adequacy position of the global banking system. In Australia the new regulations are to be phased in over two years from 1 January 2013. KPMG, Basel III *Implications and Issues*, 2011

[114] Reserve Bank of Australia, Statement of Monetary Policy, February 2012, page 49.

Figure 9.1: 10 Year Australian Commonwealth Government Bond Yield 2002 - 2012



This heightened risk aversion (or 'flight to quality') has resulted in a 9.08% cost of equity being determined in the AER's November 2011 Draft Decision for the Tasmanian electricity distribution business, where the AER applied its standard CAPM approach. This compares to the 10.20%[115] - 10.36%[116] cost of equity approved in the Access Arrangements for the South Australian and Queensland gas distribution networks only five months earlier in June 2011. This outcome is counter-intuitive and difficult to rationalise why such a large decrease in the allowed cost of equity for the Tasmanian electricity distribution business would be deemed appropriate by the AER given the short amount of time between decisions.

The sole reason for the 112bp to 128bp decrease in the return on equity for the Tasmanian electricity distribution business was due to the sharp decline in 10-year Commonwealth Government Bonds yields between June and November 2011. This reduction in the cost of equity is contrary to increases in other measures of risk, such as dividend yields and changes in the spread between Commonwealth Government Bonds and corporate debt and semi-government debt, as noted by the Reserve Bank of Australia:

115 AER, *Final Decision Envestra Ltd Access arrangement proposal for the APT Allgas Qld gas network, 1 July 2011 to 30 June 2016*, June 2011

116 AER, *Final Decision Envestra Ltd Access arrangement proposal for the SA gas network, 1 July 2011 to 30 June 2016*, June 2011

> *The strong investor preference for CGS [Commonwealth Government Bonds] and deterioration in liquidity in the state government securities market, primarily as a result of heightened risk aversion related to events in Europe, led to widening of the spread between yields on the securities (Graph 4.4). At their peak, 5-year spread had widened by around 70 basis points from where they were at the end of October for South Australia and Queensland, and by around 50 basis points for New South Wales and Victoria. In recent weeks, spreads have narrowed and issuance have picked up considerably. Yields on longer-term state government debt have increased since the previous Statement as the increase in spreads has more than offset the fall in yields on CGS, but they remain low by historical standards*[117]*.*

This suggests the AER's standard practice is currently producing a cost of equity which is (a) unusually low (b) exhibiting a high degree of variability over the short-term and (c) resulting in a rate of return that is not reflective of prevailing conditions in the market for funds.

This is supported by CEG's expert report (attachment 9.1) that explains that the cost of equity for the Tasmanian electricity distribution business is lower than any other estimate determined by the AER and that AER cost of equity estimates post-GFC have been lower than estimates prior to the crisis. These facts are illustrated in figure 9.2.

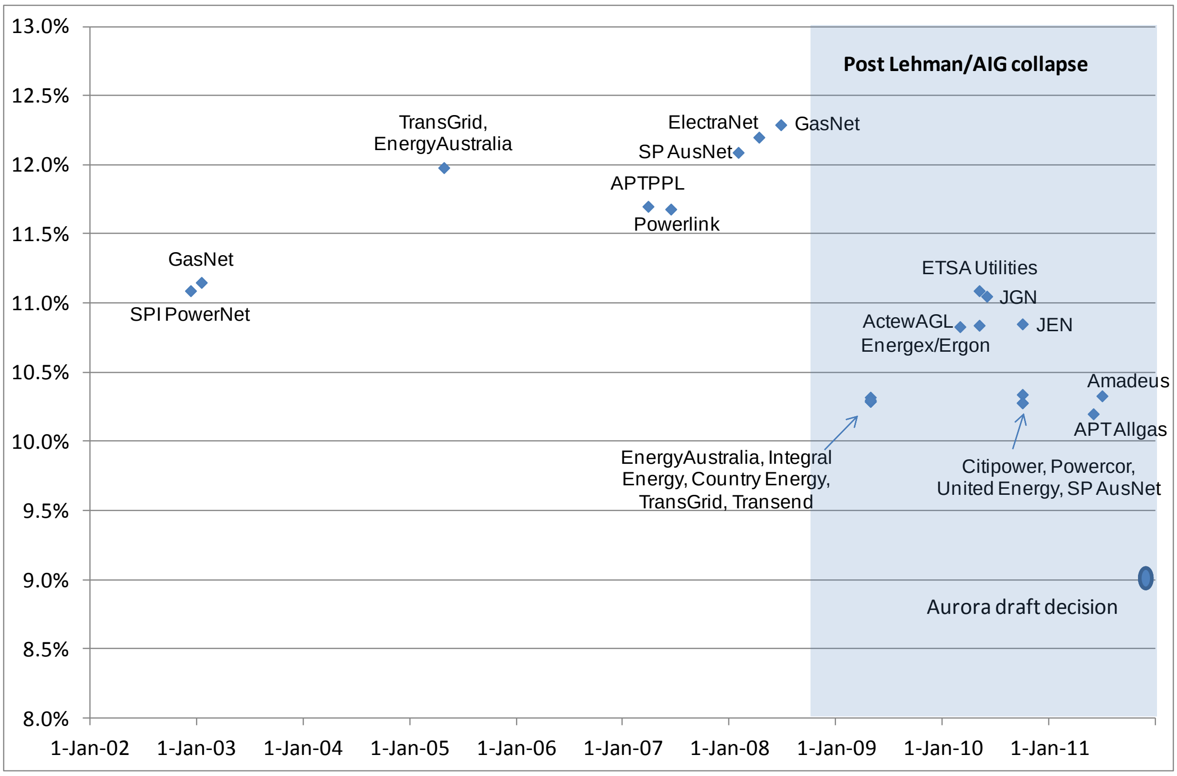
The Australian Competition Tribunal (ACT) has previously opined on the use of an unusually low risk free rate in the CAPM[118]. The Australian Competition Tribunal found that the AER is required to establish an unbiased bond rate (risk free rate in CAPM) for determining the cost of capital. The circumstances affecting the current yield on the 10-year Commonwealth Government Bonds are similar to those that prevailed in 2009 when the Australian Competition Tribunal overturned the decision by the AER to use the real risk free rate of 1.8%, on the grounds it was calculated from an averaging period that was not likely to be representative for the Access Arrangement period.

CEG considered that in the current market conditions the standard AER practice of adding a 4.8% equity premium, which is derived primarily using longer-term historical data, to the volatile short-term risk free rate as the reason for CAPM not providing a cost of equity consistent with the NGR's. CEG advise that greater consistency is required in the CAPM parameter estimates in order to provide an NGR compliant CAPM cost of equity.

117 Reserve Bank of Australia, Statement of Monetary Policy, February 2012, page 50

118 Application by EnergyAustralia and Others (No 2) [2009] ACompT 9 (25 November 2009)

Figure 9.2: Cost of equity decisions for regulated energy networks



Indeed, the Independent Pricing and Regulatory Tribunal (IPART) recently acknowledged these issues in its Final Report for the Sydney Desalination Plant:

> *The parameters used to calculate the WACC range for the decision were based on market conditions over the 20 days to 28 October 2011 (where relevant). These parameters, particularly the risk free rate and debt margin, have been affected by the market volatility and prolonged weak market following the credit crisis of 2008. The change in these factors has potentially created a disconnect between the risk free rate and the debt margin for which we use short term averages, and the market risk premium, for which we use a long term average.*[119]

Given the current unique economic conditions, and the expert advice from CEG, the AER's standard approach to estimating the rate of return on equity cannot be considered to meet the relevant criteria of the NGR when the yield on 10 year Australian Government Bonds is materially below longer-term trend levels (as per figure 9.1). This is demonstrated by the historically low cost of equity applied by the AER in the Aurora Draft Decision. Compliance with the NGR requires 'output checks' to be performed on the rate of return to ensure it reflects conditions prevailing in the market for funds. Based on the unusual market conditions currently persisting, such output checks show the AER's standard approach does not produce results compliant with rule 87.

9.4 Methodology for Determining the Rate of Return

The nominal post-tax WACC (or rate of return) will be derived using the formula below. In this formulation of the WACC corporate taxes are dealt with in the forecast cash flows.

[119] IPART, *Review of water prices for Sydney Desalination Plant Pty Limited, Water-Final Report*, December 2011, p84

WACC (nominal, post-tax) $= R_e \bullet \frac{E}{V} + R_d \bullet \frac{D}{V}$

Where:

R_e Risk adjusted post-tax cost of equity required by investors derived from the CAPM

R_d Benchmark cost of debt

E Benchmark level of equity expressed as a percentage of V

D Benchmark level of debt expressed as a percentage of V

V Sum of the benchmark debt level plus benchmark equity level (V = D + E)

Given the complexity of the above issues, Envestra has engaged appropriate experts to assist it determine the rate of return in accordance with the NGR. All advice provided by those experts has been attached to this Access Arrangement Information.

To avoid the problems with the AER's standard methodology for deriving the rate of return on equity, CEG has advised on the appropriate cost of equity to be derived using the CAPM. CEG has performed a number of output checks in order to triangulate the best estimate of the cost of equity in the prevailing market conditions. Envestra has used this expert advice to arrive at its proposed cost of equity. This process requires the application of skill and judgement, such that the proposed cost of equity is commensurate with the prevailing conditions in the market for funds and is consistent with the NGR, views of the Australian Competition Tribunal[120] and best practice principles contained in ASIC Guideline 111.

The cost of debt has been estimated with reference to the yield payable on a corporate bond of sufficient size to finance the debt portion of both the capital base and the forecast capital expenditure over the 2013 to 2017 Access Arrangement period. This notional corporate bond will be priced in accordance with the BBB+ benchmark credit rating and a 10 year term to maturity.

Envestra has commissioned PricewaterhouseCoopers ('PwC') and CEG to provide an estimate of the cost of debt on the benchmark corporate bond. Data was sourced from independent corporate bond yield service providers (e.g. UBS, AFMA and Bloomberg) and cross checked for compliance with the NGR.

9.5 Sharpe-Linter Capital Asset Pricing Model ('CAPM')

The CAPM is the *ex-ante* basis for estimating the risk adjusted return on equity required by investors. The general formula used to derive the cost of equity is the CAPM, which is expressed as follows:

$$E(R_i) = R_f + \beta_i[E(MRP)]$$

Where

$E(R_i)$ is the expected return on asset *i* (or the cost of equity (R_e));

[120] Australian Competition Tribunal in Application by Telstra Corporation Limited ABN 33 051 775 556 [2010] ACompT.

R_f is the nominal risk free rate of return (ie. zero variance in returns);

E(MRP) is the expected Market Risk Premium and is calculated as $E(R_m) - R_f$;

$E(R_m)$ is the expected return on the market portfolio; and

β_i is the systematic risk of asset *i.*

As can be seen from the CAPM formula the market risk premium, equity beta and the risk free rate are linked together to estimate the required rate of return on equity. Hence, they cannot be considered in isolation. To simply combine estimates of the risk free rate, market risk premium and equity beta that have been derived from disparate time periods will be unlikely to result in an estimate of the return on equity that satisfies the requirements of the NGR.

Standard & Poor's acknowledge this issue by providing flexibility in CAPM parameter selection so as to derive a best estimate of the *ex-ante* cost of equity.

> "*The cost of equity is typically derived from the Capital Asset Pricing Model (CAPM), which requires some estimate of the firm's equity market beta. Since the historical beta may bear little relevance for the future, analysts are granted the flexibility to modify their estimates to allow for what they view as realistic assumptions of relative share price volatility going forward*"[121].

Despite these, and other well known shortcomings of the CAPM, and the statistical uncertainty surrounding some of the input parameters, Envestra proposes to use the CAPM to determine the regulatory rate of return (or WACC). However, it will not be applied in a mechanistic way, but in a manner that provides a rate of return on equity that is consistent with the NGR, which is akin to that used by market practitioners (such as Standard & Poor's) with appropriate 'output checks'.

9.6 CAPM Input Parameter Values

As noted the CAPM has three parameter inputs (i) the risk free rate (ii) the market risk premium and (iii) the equity beta. The derivation of each of these input parameter values is explained below.

9.6.1 Risk Free Rate

The risk free rate (being the return on a truly free risk asset) cannot be measured directly as there are no such riskless assets. Therefore proxies are used. To determine the risk free rate it is necessary to identify a proxy and then determine the period over which the best estimate of that proxy is to be observed.

The real risk free rate, not the nominal risk free rate, is the relevant input for determining the revenue requirement in the AERs Post-Tax Revenue Model (because inflation is treated as a pass through). Consequently, it is the real risk free rate that should be the focus of any analysis on the subject.

Envestra has followed regulatory practice, and practitioner convention, and used the nominal yield on Commonwealth Government Bonds with a term to maturity of 10 years as the proxy for the nominal risk free rate. In determining the appropriate averaging period for estimating the risk free rate it is necessary to make an assessment about whether it is representative of investor requirements commensurate with prevailing conditions in the market for funds.

121 Standard & Poor's, *Stock Appreciation Ranking System (STARS): Methodology, Analysis & Performance Attribution*, June 2005, p12

Given the historically low yields on Commonwealth Government Bonds currently pertaining, a short-term averaging period will not reflect prevailing conditions in the market for funds over the 2013 to 2017 Access Arrangement period, and as such, will not provide an appropriate estimate of the risk free rate for use in the CAPM. The task therefore is to ascertain the appropriate term to measure the yield on 10 year Commonwealth Government Bonds for use in estimating the cost of equity that complies with the NGR and the National Gas Objective.

9.6.1.1 Short-term averaging period

Past practice has been to estimate the nominal risk free rate by calculating the average 10 year Commonwealth Government Bond yield over 10 to 40 trading days. This is termed the 'current' risk free rate as it is based on a short-term average from data in the recent past. For the purposes of this submission an indicative averaging period of 20 trading days from 21 November to 16 December 2011 provides a 3.99% (1.44%) nominal (real) risk free rate.

In its June 2011 Final Decisions for Envestra's South Australian and Queensland gas distribution networks the AER used a short-term real risk free rate of 2.94% which is more than double the 1.44% derived from the current short-term average. Furthermore, it is relevant to note that the real risk free rate of 1.44% calculated over 21 November to 16 December 2011 is substantially lower than the 1.8% real risk free rate that was overturned in the EnergyAustralia decision. The Australian Competition Tribunal[122] commented:

> *"The Tribunal considers that an averaging period during which interest rates were at historically low levels is unlikely to produce a rate of return appropriate for the regulatory period."*

Therefore, at the current time it is unlikely that the rate of return on equity calculated in the CAPM using the 'current' risk free rate and the AER's preferred equity risk premium of 4.8%, which is derived predominantly from longer-term historic averages, will satisfy the requirements of rule 87(1). However, it could comply with rule 87(1) if a higher equity beta and/or a 'current' estimate of the market risk premium were used. This is addressed further below.

9.6.1.2 Long-term averaging period

In circumstances where the current yield on 10 year Commonwealth Government Bonds is unusually high, or low, an alternative method for deriving the risk free rate is to measure the yield on 10 year Commonwealth Government Bonds over a longer averaging period.

In *Energy Australia*, the Australian Competition Tribunal noted that there is no special virtue in an averaging period close to the date of the AER's Final Decision,[123] and accepted the Applicants' argument that the AER's averaging period was in a period of unusually low yields and therefore was not appropriate for the setting of a rate of return over the forthcoming regulatory period.[124]

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[122] Application by EnergyAustralia and Others (includes corrigendum dated 1 December 2009) [2009] ACompT 8 (12 November 2009), paragraph 114.

[123] Application by EnergyAustralia and Others (includes corrigendum dated 1 December 2009) [2009] ACompT 8 (12 November 2009), Paragraph 111,

[124] Application by EnergyAustralia and Others (includes corrigendum dated 1 December 2009) [2009] ACompT 8 (12 November 2009), Paragraphs 109-111, 114.

CEG have advised that its preferred method for estimating the long-term real risk free is to use the historical average yield on the inflation indexed Commonwealth Government Bonds with a term to maturity of 10 years. CEG have recommended an averaging period commencing in 1993 as this was when the RBA formally implemented its 2 to 3% inflation targeting policy. Based on this CEG recommend that a 3.40% real risk free rate (5.99% nominal) be used in the CAPM.

Therefore, Envestra is of the view that the real risk free rate of 3.40% is the appropriate real risk free rate (5.99% nominal) for use in the CAPM. This long-term approach is consistent with the standard AER approach for estimating the equity beta and MRP, which are based on longer term averages.

9.6.2 Market Risk Premium

The market risk premium ('MRP') used in the CAPM is the *ex-ante* premium above the risk-free rate of return that investors expect to earn on the 'market portfolio'. The 'market portfolio' comprises all risky assets – not only shares in listed companies, but also shares in private companies, risky debt securities, real estate, commodities, and other physical assets, and even human capital[125].

Regulatory practice has been to use the stock market as the proxy for the market portfolio and deduct the corresponding yield on 10 year Commonwealth Government Bonds to derive the historical MRP. The AER appears to attribute significant weight to the long-term historical average MRP value in its most recent decisions for South Australian and Queensland gas distribution networks and the Tasmanian electricity distribution network. This has resulted in 6% being the AER's presently preferred estimate of MRP.

Given the concerns outlined in section 9.6.1 about the use of the 3.99% nominal (1.44% real) risk free rate not producing a return on equity with the CAPM that satisfies the requirements of rule 87(1), two estimates of the MRP are considered:

(1) A 'current' MRP that matches with the risk compensation expectations embedded into the 'current' risk free rate; and

(2) A 'longer-term' MRP where short-term movements are averaged out in both the MRP and risk free rate.

The resulting CAPM cost of equity derived from 'current' and 'long-term' risk free rates and MRP estimates should provide a reasonably consistent outcome if estimated correctly.

9.6.2.1 'Current' Market Risk Premium

Envestra has received expert advice from CEG demonstrating that the 'current' MRP is well above long term historic levels. CEG used the dividend growth model to estimate the cost of equity for the market as a whole (equity beta of one) then derived the prevailing MRP relative to the prevailing Commonwealth Government Bonds yield. This method has the benefit of removing the error in the AER's standard methodology as the 'current' MRP is estimated consistently with the 'current' risk free rate. The dividend growth model is a well accepted approach to estimating the cost of equity on a forward looking basis.

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125 Brealey R, Myers S, Partington G, Robinson D (2000) *Principles of Corporate Finance*, 1st Australian edition, McGraw-Hill Australia, p209

CEG estimated the market cost of equity as at 31 December 2011 (for a beta of one) to be 12.3%, with the associated MRP of 8.5% and nominal risk free rate of 3.8%. This is based on the AMP method[126] using end December 2011 dividend yields from the RBA and long-run nominal dividend growth of 6.6%. If we assume a relatively constant market-wide (beta of one) 12.3% cost of equity and a nominal risk free rate of 3.99%, this methodology produces a 'current' MRP of 8.3% (i.e. 12.3% minus 3.99% = 8.31%).

Envestra therefore proposes a 'current' MRP of 8.3% as the point estimate for use in the CAPM if applied with the 'current' nominal risk free rate of 3.99% (1.44% real) using an averaging period between 21 November and 16 December 2011. The 'current' MRP is well above its long-term average value and above the AER's current preferred value of 6%.

9.6.2.2 Long-term Market Risk Premium

Handley[127] estimates the long-term arithmetic mean for the MRP, with a theta of 0.35, to be 6.5% for the period 1958-2009 and 6.4% over the 1958-2010 period[128]. Geometric averages do not provide an unbiased estimate of the MRP so are not a relevant consideration for use in the CAPM (see attachment 9.2).

In the AER's Draft Decisions for Envestra's South Australian and Queensland gas distribution networks the AER concluded that a long term MRP of 6% was consistent with the latest long term historical estimates of excess returns[129]. The Australian Competition Tribunal found that the AER had not exercised its discretion incorrectly in determining an MRP of 6%,[130] based on the evidence before the Tribunal. In its June 2011 Final Decisions for Envestra's South Australian and Queensland gas distribution networks the AER used a nominal risk free rate of 5.56% (2.94% real), an equity beta of 0.8 and an MRP of 6% to determine that a 10.36% cost of equity was compliant with the NGR.

For the purposes of calculating the CAPM cost of equity with parameter values derived from longer-term averages Envestra proposes a 'long-term' value for the MRP of 6%.

9.6.3 Equity Beta for use in CAPM

The AER benchmark value for equity beta is 0.8 with the associated gearing of 60% debt to total capital. Envestra notes that Grant Samuel in its Independent Expert Report in relation to "the Proposed Acquisition of the Alinta Assets from Singapore Power International Pte Limited" dated 5 November 2007 used an equity beta of 0.8-0.9 to value the energy distribution businesses.

126 CEG, *Internal consistency of risk free rate and MRP in the CAPM, Prepared for Envestra, SP AusNet, and Multinet, APA Group, March 2012*

127 John C. Handley, *Memorandum: Additional Estimates of the Historical Equity Risk Premium for the Period 1883 to 2010*, 25 May 2011.

128 1958 was considered to be the critical break in the sample period that reflected a shift from poor to relatively good quality data. Pre-1958 data was considered to likely over-state equity returns and therefore the over-state MRP. Handley used the post-1958 data in his analysis. AER, *Final Decision Envestra Ltd Access arrangement proposal for the SA gas network, 1 July 2011 to 30 June 2016*, June 2011, page 186-7

129 Australian Competition Tribunal, Application by Envestra Ltd [2012] ACompT3 (11 January 2012), Para 128

130 Australian Competition Tribunal, Application by Envestra Ltd [2012] ACompT3, (11 January 2012), Para 141

However, an equity beta with a value of 0.8 was used in the CAPM to derive the cost of equity in Access Arrangements for the South Australian[131] and Queensland[132] gas networks. For the purposes of this submission, Envestra proposes a value for equity beta of 0.8.

9.6.4 CAPM Cost of Equity

The CAPM estimates the risk adjusted returns required by equity holders in the form of dividends and capital gains (i.e. the cost of equity). The parameter values for the 'current' and 'long-term' applications of the CAPM are summarised in table 9.1 below.

Table 9.1: CAPM Parameters& Cost of Equity Estimate

CAPM Parameters	'Current' Parameters	'Long-term' Parameters
Nominal Risk Free Rate	3.99%	5.99%
Market Risk Premium	8.3%	6%
Equity Beta	0.8	0.8
Cost of Equity	10.6%	10.8%

Envestra proposes a 10.8% cost of equity estimated using the CAPM. The 'long-term' approach is preferred as this approach avoids short-term movements in Commonwealth Government Bond yields from distorting the required return on equity, it is consistent with the method used to derive the other CAPM variables (equity beta and MRP) and it reflects the long-term nature of the assets it is funding.

The next stage is to check the CAPM output against alternative estimation techniques to ensure it complies with the NGR.

9.6.5 Outcomes from Alternative Asset Pricing Models

Expert advice from CEG, NERA and Capital Research was sought to provide cost of equity estimates from other appropriate methods in order to cross-check the 10.8% proposed cost of equity. Other gas distribution network cost of equity decisions by the AER have also been assessed for comparison, as the risks associated with providing reference services from these businesses are similar to those in the Victorian network. The cost of equity estimates from this 'output' checking analyses are summarised in the table below.

131 AER, *Final Decision Envestra Ltd Access arrangement proposal for the SA gas network, 1 July 2011 to 30 June 2016*, June 2011

132 AER, *Final Decision Envestra Ltd Access arrangement proposal for the Qld gas network, 1 July 2011 to 30 June 2016*, June 2011

Table 9.2: Output Check of Cost of Equity Estimates

Asset Pricing Model	Range for nominal post-tax cost of equity
CAPM ('current' R_f, β = 0.8, MRP=6%)	8.79%
CAPM (Long-term real R_f, β = 0.8, MRP=6%)	10.80%
CAPM (Allgas June 2011)	10.20%
CAPM (Envestra June 2011)	10.36%
CAPM (ActewAGL 2010)	10.83%
CAPM (Jemena 2010)	11.05%
NERA ('current' R_f, β = 0.8, MRP=8.44%)	10.74%
NERA Black CAPM	12.14%
Capital Research (R_f = 3.76%, β = 0.8, MRP=9.56%)	11.4%
CEG Recommended Range	10.6% - 14.6%

Envestra notes that the AER's standard application of the CAPM produces the lowest rate of return on equity of any of the other regulatory decisions. CEG advise that this is unlikely to provide a return on equity reflective of prevailing market conditions.

Recent cost of equity decisions by the AER for other gas distribution businesses have provided a cost of equity between 10.2% and 11.05%. The expert estimates of the cost of equity for the benchmark gas distribution business range between 10.6% and 14.6% and are listed below:

- CEG – who estimate a range of: 10.6% to 14.6%[133];
- Capital Research – who estimate 11.4% (attachment 9.3);
- NERA – who estimate a range of 10.74% to 12.14% (attachments 9.4, 9.5 and 9.6),

Envestra has been guided by the expert views of CEG in selecting the point estimate of 10.8%% for the cost of equity to be used in the 2013 to 2017 Access Arrangement:

> *"In my view there are two possible sources of an estimate of the historical average risk free rate that can be used in conjunction with a historical average MRP estimate (such as the AER's 6% estimate). My preference is to adopt the historical average yield on inflation indexed CGS. This yield is, by definition, the required return on these CGS bonds after inflation (which is separately compensated based on actual inflation over the life of the bond). Based on a time series from 1993 the average yield on indexed CGS was 3.40%. I note that this is a conservative estimate because, from late 2008, the AER ceased using indexed CGS as the risk free rate proxy because of evidence that scarcity of supply was biasing down the required yield on these CGS.*

133 CEG, *Internal consistency of risk free rate and MRP in the CAPM, Prepared for Envestra, SP AusNet, and Multinet, March 2012*

Combining my best estimate of the historical average real required return on 10 year CGS with a beta of 0.8 and an MRP of 6% gives a real cost of equity of 8.2%. If expected inflation going forward is 2.5% then a 5.99% nominal yield is required to deliver the same 3.40% real yield. Using this nominal CGS yield with a beta of 0.8 and an MRP of 6% gives a nominal cost of equity of 10.78%."[134]

Under current market conditions, the combination of short-term measurements of the risk free rate and long-term historical values of the MRP in the CAPM will not provide the best estimate of the cost on equity. Therefore, the AER's standard application of the CAPM will not produce an estimate of the cost of equity in accordance with the rules.

Envestra's proposed cost of equity is 10.8%, which has been cross-checked against a range of other estimates from recent regulatory decisions and estimates provided in four independent expert reports of the prevailing cost of equity (i.e. NERA, Capital Research and CEG). In particular, Envestra's estimate of 10.8% is based on using internally consistent long term parameter values in the CAPM that remove short term distortions. The resultant cost of equity is also consistent with the expert advice provided by CEG, NERA and Capital Research (albeit at the lower end of the range of estimates).

On the basis of the evidence, Envestra submits that a cost of equity of 10.8% derived using the CAPM can be regarded as consistent with the NGR and the National Gas Objective.

9.7 Cost of Debt

The benchmark cost of debt (and associated debt risk premium or 'DRP') is that which will allow the benchmark business to finance the debt portion of both the capital base and the forecast capital expenditure over the 2013 to 2017 Access Arrangement period.

In the June 2011 Final Decisions for Envestra's South Australian[135] and Queensland[136] gas distribution networks the AER estimated the benchmark debt risk premium by applying equal weight to the extrapolated Bloomberg fair value curve and a single bond issued by APT Pipelines Limited maturing in 2020. Envestra considered the AER had erred in its approach and sought review of the issue by the Australian Competition Tribunal. The Tribunal found that the AER's methodology of averaging the Bloomberg fair value curve with the APT bond was in error and directed the use of the extrapolated Bloomberg fair value curve for estimating the DRP. The Tribunal found that there was no reason shown from the available material why the use of the extrapolated Bloomberg fair value curve should not be adopted.[137]

In its recent Aurora and Powerlink draft decisions, the AER amended its DRP estimation methodology by averaging the DRP on a sample of nine bonds, with no weight given to the Bloomberg fair value curve. Given the Tribunal's previous findings in favour of the use of the extrapolated Bloomberg fair value curve Envestra has concluded that the DRP estimation methodology used in the Aurora and Powerlink draft decisions will not satisfy the requirements of the rules.

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134 CEG, *Internal consistency of risk free rate and MRP in the CAPM, Prepared for Envestra, SP AusNet, and Multinet, March 2012*, page 44.

135 AER, *Final Decision Envestra Ltd Access arrangement proposal for the South Australian gas network, 1 July 2011 to 30 June 2016*, June 2011

136 AER, *Final Decision Envestra Ltd Access arrangement proposal for the Queensland gas network, 1 July 2011 to 30 June 2016*, June 2011

137 Australian Competition Tribunal, Application by Envestra Ltd [2012] ACompT3 (11 January 2012), Para 123

To test this conclusion Envestra obtained independent expert advice from PwC[138] and CEG[139] in relation to the benchmark cost of debt and DRP (attachments 9.7 and 9.8). Both the PwC and CEG reports have taken into consideration the Tribunal's comments regarding the proper composition of comparison bond samples[140] and assessed the accuracy of the extrapolated Bloomberg fair value curve by a number of different methods.[141] The expert reports provided an estimate of the cost of debt consistent with the benchmark BBB+ 10 year Australian corporate bond and addressed the following related matters:

- the suitability of Bloomberg fair value yield curves (extrapolated to 10 years) in producing cost of debt estimates that meet the NGR requirements;
- the implications of recent AER decisions and relevant decisions handed down by the Australian Competition Tribunal;
- the application of the methodology used in the Aurora and Powerlink draft decisions to produce a cost of debt estimate that accords with the NGR;
- different methods of fitting a yield curve to the observed bond yields based on transaction data across the term structures; and
- the possible use of additional information, including yields of bonds issued overseas, swapped back into Australian dollars.

In regard to the amended methodology employed by the AER in the Aurora and Powerlink draft decisions CEG found it was not an appropriate methodology to estimate the benchmark DRP because:

> *….the consideration of nine bonds rather than one [APT Pipelines bond maturing in 2020] only partially addresses the risk that the sample will be unrepresentative and/or that the sample includes outliers that should not be included*
>
> *The average DRP of the bonds in the AER's sample does not result in an estimate that is representative of the wider information available from the population of bonds.*[142]

PwC critiqued the amended AER methodology in the Powerlink Draft Decision (which is the same as the Aurora Draft Decision) and found the extrapolated Bloomberg fair value curve provided a better DRP estimate:

> *We recommended that the AER adopt the upper end of the range of estimates, which is defined by the extrapolated Bloomberg curve, as the econometric evidence indicated a debt risk premium that was relatively closer to the extrapolated Bloomberg curve.*[143]

CEG recommended the use of the extrapolated Bloomberg fair value curve due to the depth and breadth of information incorporated into it, and as it is built for, and commercially provided to, debt market participants who pay to use it for commercial purposes.

138 PwC, *Estimating the Debt Risk Premium*, March 2012.
139 CEG, *Estimating the regulatory debt risk premium for Victorian gas businesses*, March 2012
140 Australian Competition Tribunal, Application by Envestra Ltd [2012] ACompT3 (11 January 2012), Para 118
141 Australian Competition Tribunal, Application by Envestra Ltd [2012] ACompT3 (11 January 2012), Para 78
142 CEG, *Estimating the regulatory debt risk premium for Victorian gas businesses*, March 2012
143 PwC, *Estimating the Debt Risk Premium*, March 2012

> *In deriving its fair value curves Bloomberg has a great deal of information available to it – including, but not limited to, estimates of market prices of many hundreds of bonds across a range of credit ratings and maturities (including but, again, not limited to the BBB to A- bonds charted in this report).*[144]

This was supported by PwC who commented that the Bloomberg fair value curve is the most comprehensive published embodiment of market opinion about the cost of debt. Using different methodologies to cross-check the Bloomberg fair value curves both PwC and CEG have found that it continues to be most appropriate basis upon which to estimate the benchmark cost of debt and that there is no basis to depart from its use for the purpose of estimating the benchmark cost of debt and DRP in accordance with the rules. PwC noted that the Australian Competition Tribunal has continued to endorse the extrapolated Bloomberg fair value yield curve as an appropriate method for estimating the benchmark cost of debt.

For the measurement period from 21 November 2011 to 16 December 2011 both PwC and CEG estimate the benchmark cost of debt to be 7.91%, derived from the 'current' nominal 10 year Commonwealth Government Bond yield (i.e. base rate) of 3.99% and the benchmark debt risk premium of 3.92%.

Envestra will lodge a separate and confidential submission with the AER to agree, prior to the final decision, the averaging period for setting the cost of debt allowance for the purpose of the final decision. This will allow Envestra to hedge the base rate in the cost of debt, such that it aligns with the rate of return incorporated into 2013 to 2017 reference tariffs. Envestra will request that the agreed averaging period remains confidential until the AER delivers its final decision.

9.8 Other Parameter Values

9.8.1 Gearing

The AER benchmark gearing is 60% debt to total capital, which it approved in the recent Access Arrangements for Envestra's South Australian[145] and Queensland[146] gas networks. For the purposes of this submission Envestra proposes a benchmark gearing level of 60% (total debt to total capital) as consistent with the NGR and the National Gas Objective.

9.8.2 Inflation

Envestra has estimated the annual rate of inflation consistent with the approach taken by the AER in other regulatory determinations. That is, the expected rate of inflation has been calculated on the basis of the mean of the CPI forecasts of the most recent Reserve Bank of Australia Statement on Monetary Policy (February 2012) over a 10 year period. The forecasts proposed to be used by Envestra are:

(a) 2.7% for the period to December 2013; and

(b) 2.5% for each year from December 2013.

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144 CEG, *Estimating the regulatory debt risk premium for Victorian gas businesses*, March 2012

145 AER, *Final Decision EnvestraLtd Access arrangement proposal for the SA gas network, 1 July 2011 to 30 June 2016*, June 2011

146 AER, *Final Decision EnvestraLtd Access arrangement proposal for the Qld gas network, 1 July 2011 to 30 June 2016*, June 2011

The mean of these forecasts is 2.5% and this is proposed as the forecast for inflation over the 2013 to 2017 Access Arrangement period.

9.8.3 Debt Raising Costs

Envestra has relied on estimates of Australian debt raising costs for the notional benchmark regulated entity as contained in the report from Deloitte (attachment 9.9). Deloitte followed a similar methodology to estimate the debt raising costs as the 2004 Allen Consulting Group report entitled *Debt and Equity Raising Costs,* which has been relied upon by the AER in recent regulatory decisions. Given the significant changes in debt markets since 2004 the Deloitte report provides a more accurate estimate of the current costs associated with debt financing the capital base and capital expenditure program of the benchmark regulated entity.

Deloitte recommended annualised debt raising costs in the domestic market of 15 basis points per annum. Envestra proposes to include 15 basis points per annum as the benchmark level of debt raising costs in the operating expenditure forecasts.

9.8.4 Liquidity Risk and Costs

Liquidity risk is the risk that a business will have insufficient funds to meet its financial commitments in a timely manner. The two key elements of liquidity risk are short-term cash flow risk and long-term funding risk. The long-term funding risk includes the risk that loans may not be available when the business requires them or that such funds will not be available for the required term or at acceptable cost. All businesses need to manage liquidity risk to ensure that they remain solvent.[147]

In September 2011 Standard & Poor's released its updated criteria for assessing liquidity risk and how it directly impacts an issuer's credit rating (attachment 9.10). Standard & Poor's require an investment grade issuer (i.e. BBB- or higher) to have an "adequate" level of liquidity as defined in the criteria:

> *Adequate liquidity is rating-neutral. To avoid the risk of default, a company's liquidity must be sufficiently robust to absorb a moderate level of stress. Accordingly, for a company to receive a rating of 'BBB-' or higher, its liquidity must be scored adequate or stronger all investment-grade companies must have at least adequate liquidity.* [148]

Therefore, in order for a benchmark regulated network service provider to maintain the BBB+ credit rating it must achieve "adequate" levels of liquidity throughout the Access Arrangement period.

A lack of liquidity could precipitate the default of an otherwise healthy entity. Further, liquidity is an independent characteristic of a company, measured on an absolute basis, and the assessment is not relative to industry peers or other companies in the same rating category. The implication is that the liquidity for the BBB+ rated benchmark regulated network service provider must be assessed as "adequate", or above, on the basis of its expected cash flows over the Access Arrangement period.

Standard & Poor's undertake a "sources and uses" analysis of liquidity to determine where an individual company lies on its liquidity spectrum. Sources and uses of liquidity as defined by Standard & Poor's are listed below:

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[147] *CPA Australia Ltd, Guide to managing liquidity risk, 2010*

[148] Standard & Poor's, *Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers,* September 2011

Sources:

- Cash and liquid investments;
- Forecasted funds from operations (FFO), if positive;
- Forecasted working capital inflows, if positive;
- Proceeds of asset sales (when confidently predictable);
- The undrawn, available portion of committed bank lines maturing beyond the next 12 months; and
- Expected ongoing cash injections from a government or corporate group members, as appropriate.

Uses:

- Forecasted funds from operations, if negative;
- Expected capital spending;
- Forecasted working capital outflows, if negative;
- All debt maturities (either recourse to the company or which it is expected to support);
- Any required cash-based, postretirement employee benefit top-up needs;
- Credit puts that cause debt acceleration or new collateral posting requirements in the event of a ratings downgrade of up to three notches; and
- Contracted acquisitions and expected shareholder distributions under a stress scenario, including expected share repurchases.

To attain an "adequate" level of liquidity (i.e. the minimum for an investment grade credit rating) there are two main quantitative analyses used by Standard & Poor's to assess liquidity (i) "sources" divided by "uses" must be greater than 1.2 times and (ii) "sources" less "uses" must be positive after allowing for a 15% decline in EBITDA. The main source of excess liquidity for regulated gas networks, such as Envestra, is undrawn available committed bank debt. The cost of this source of liquidity is significant but not captured in the cost of debt or the operating cost building block component of revenue. Envestra estimates that the costs of maintaining an "adequate" level of liquidity for the benchmark regulated gas network to be $1.9 million ($ nominal) per annum on average over the 2013 to 2017 Access Arrangement period.

9.9 Proposed Rate of Return

The nominal post-tax WACC of 9.06% has been derived from the formula below. The rate of return on capital (or WACC) proposed in accordance with the NGR is the cost of equity and the cost of debt weighted by the respective proportions of equity (40%) and debt (60%) in the benchmark capital structure.

WACC (nominal, post-tax) $= R_e \bullet \frac{E}{V} + R_d \bullet \frac{D}{V}$

where

R_e	10.8%, which is the risk adjusted post-tax cost of equity required by investors derived from the CAPM
R_d	7.91% cost of debt
E	40%, which is the benchmark level of equity expressed as a percentage
D	60%, which is the benchmark level of debt expressed as a percentage
V	Sum of assumed debt level plus assumed equity level (V = D + E)

For the reasons set out in this proposal, Envestra submits that a WACC of 9.06% is the value that best gives effect to the requirements of the National Gas Objective, the National Gas Law and the National Gas Rules.

10. Cost of Tax

10.1 Introduction

The regulated revenue requirement set by the AER must include a benchmark allowance for the tax liability (or cost of tax) of the distributor over the regulatory period. There are two approaches that can be used to determine the benchmark cost of tax for the distributor. The first is by applying a pre-tax regulatory framework to determine total revenue while the second is to adopt a post-tax framework.

The pre-tax approach incorporates the cost of tax directly into the weighted average cost of capital (WACC) used to determine the rate of return component (or building block) of total revenue. The post-tax approach involves including as a separate building block a specific forecast of the tax liability of the distributor (and excluding tax from the WACC).

The post-tax approach was applied to determine the cost of tax by the previous regulator in Victoria. Envestra notes that the AER has in the past expressed a strong preference towards a post-tax approach on the basis that it "is superior in that it facilitates an accurate allowance for tax in setting regulatory revenues."[149]

Additionally, the use of a post-tax approach is a Fixed Principle in the current Access Arrangement as follows:

> *"The Regulator will apply the same post-tax approach to the Capital base in the Third Access Arrangement Period and subsequent Access Arrangement Periods, as was applied in the Second Access Arrangement Period."*[150]

This Fixed Principle applies for a period of 30 years starting from 1 January 2008.

Envestra therefore intends to continue to adopt a post-tax approach to determine the cost of tax component of total regulatory revenue. This chapter describes how Envestra has determined the benchmark cost of tax to apply over the 2013 to 1017 Access Arrangement period.

10.2 Requirements of the National Gas Rules

The NGR provides the overarching framework for determining the benchmark cost of tax component of total revenue. Rule 72(1)(h) requires that:

> *"The access arrangement information for a full access arrangement proposal (other than an access arrangement variation proposal) must include.... the proposed method for dealing with taxation, and a demonstration of how the allowance for taxation is calculated".*

Rule 76(c) provides that:

> *"Total revenue is to be determined for each regulatory year of the access arrangement period using the building block approach in which the building blocks are:*

149 AER 2007, Electricity Distribution Network Service Providers Transition of Energy Businesses from Pre-tax to Post-tax Regulation, Issues Paper, June 2007, pg. 51.
150 Envestra Access Arrangement for Victorian Distribution System (2 June 2008) – Part B, page 12.

> (c) *if applicable – the estimated cost of corporate income tax for the year."*

Rule 74(2) states that:

> *"A forecast or estimate:*
>
> (a) *Must be arrived at on a reasonable basis; and*
>
> (b) *Must represent the best forecast or estimate possible in the circumstances."*

10.3 Calculating the Cost of Tax

Envestra intends to determine the benchmark cost of tax (BCT) for each year of the 2013 to 2017 Access Arrangement period in accordance with the following formula:

$$BCT = (RTI_t x STR_t)(1 - \gamma)$$

where:

- RTI_t is an estimate of the regulatory taxable income for regulatory year *t* that would be earned by a benchmark efficient distributor as determined by the AER post-tax revenue model (PTRM);
- STR_t is the expected statutory tax rate for regulatory year *t*; and
- γ (gamma) is the assumed utilisation of imputation credits.

Specifically, RTI is calculated as total regulatory revenue (excluding the cost of tax) less operating expenditure, tax depreciation and interest expense. All of the inputs used to determine the RTI, aside from tax depreciation, are taken directly from the building blocks used to determine total regulatory revenue. The calculation of tax depreciation is set out in section 10.4.

The STR is set at 30% consistent with the prevailing corporate tax rate applying in Australia. The value of imputation credits (γ or gamma), like tax depreciation, is a specific input required to determine the cost of tax that is not elsewhere determined. The value of imputation credits used by Envestra to determine the cost of tax is explained in section 10.5.

10.4 Adjusting the Tax Asset Base

Determining the amount of tax depreciation to include in calculating the BCT requires Envestra to set the opening tax asset base (TAB) as at 1 January 2013 (the start of the 2013 to 2017 Access Arrangement period). This is done by adjusting the forecast TAB set by the Essential Services Commission of Victoria (ESCV) over the 2008 to 2012 Access Arrangement period for actual information.

The opening TAB then needs to be adjusted for forecast capital expenditure, disposals and tax depreciation over the 2013 to 2017 Access Arrangement period.

10.4.1 Opening TAB

As already noted, the previous regulator (the ESCV) had applied a post-tax approach to determine the cost of tax since 1 January 2003.

Given this, an opening TAB was established as at 1 January 1998 that has since been adjusted for capital expenditure, disposals and tax depreciation. With regard to the latter, a range of methods have been used to determine tax depreciation depending on the relevant tax law applying at the time.

The ESCV adjusted the TAB up until 1 January 2007 based on actual information. The ESCV then adjusted the TAB for forecast information from this date for the purposes of calculating the BCT over the 2008 to 2012 Access Arrangement period. Envestra has therefore updated the TAB from 1 January 2007 for actual capital expenditure through to 2012 using the same information as that used to adjust the regulatory asset base (RAB) over this period (see table 10.1).

Table 10.1: TAB Roll Forward, 2008 to 2012

$M nominal	2008	2009	2010	2011	2012
Opening TAB	242.2	261.0	271.7	292.5	329.6
add Gross Capital Expenditure	50.8	43.6	55.1	74.5	97.1
less Tax Depreciation	32.0	32.9	34.3	37.4	42.9
Closing TAB	261.0	271.7	292.5	329.6	383.8

Note: 2007 TAB calculations have replaced forecast capital expenditure with actual capital expenditure for that year.

10.4.2 Adjusting the TAB over the 2013 to 2017 Access Arrangement period

The opening TAB of $383.8 million has been adjusted for forecast information over the 2013 to 2017 Access Arrangement period. Again, the forecast capital expenditure and additions are consistent with that used for adjusting the RAB over this period[151]. The lives used to determine tax depreciation in respect of capital expenditure from 2013 are set out in table 10.2.

Table 10.2: Tax Depreciation Methods and Lives

Asset Category	Tax Depreciation Life
Mains & Services	20
Meters - Domestic	15
Meters - Industrial & Commercial	15
Land & Buildings	40
Other Assets	10

The tax depreciation methods and lives applied to capital expenditure are the same as that recently approved by the AER in respect of our South Australian and Queensland networks.[152] Envestra at the time had its methodology reviewed by PricewaterhouseCoopers (PwC) who found that *"the method that has been applied by Envestra is consistent with the decisions that are available to a business under Federal tax law and moreover that the method is consistent with Envestra's own practice."*[153]

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151 Envestra notes that gross capital expenditure is included in the TAB and net expenditure is included in the RAB. The difference in the capital expenditure used to adjust the TAB and the RAB therefore reflects customer contributions.

152 For example, see: AER 2011, *'Envestra Ltd Access arrangement proposal for the SA gas network'*, Final Decision, July 2011.

153 See: PWC 2010, *'Post Tax Revenue Model Methodology – Review of Initial Taxation Asset* Base', which can be found as Attachment 10-1.

In accepting this approach, the AER in its Draft Decision for South Australia (pp. 105-106) stated:

> *"The AER has reviewed the tax asset lives and finds no issue with the tax asset lives as proposed by Envestra. The standard tax lives proposed by Envestra are consistent with the requirements of the Income Tax Assessment Act 1997. From 1 July 2002, the effective lives of gas distribution assets became subject to a statutory cap of 20 years. Envestra's proposed standard tax asset lives are consistent with these caps. Therefore, the AER accepts the standard tax asset lives proposed by Envestra."*

This decision was carried through to the AER's Final Decision for Envestra's South Australian (and Queensland) network, which was released in July 2011. There has been no relevant change to tax law in the 9 months since the AER made its South Australian Final Decision. Likewise, there has been no change in tax law from when PwC gave its advice to Envestra in September 2010.

The proposed approach to calculating tax depreciation is therefore consistent with the relevant tax law and previous decisions made by the AER. As with other elements of our Access Arrangement proposal, Envestra is seeking to align the approach taken to determine regulatory parameters with that used for other networks where this is practical (for example, as per Envestra's approach to setting reference tariffs and terms and conditions, as set out in chapters 14 and 16 respectively). The resultant roll-forward of the TAB is shown in table 10.3.

Table 10.3: TAB Roll Forward, 2013 to 2017

$M nominal	2013	2014	2015	2016	2017
Opening TAB	383.8	504.6	652.8	756.5	866.7
add Gross Capital Expenditure	169.0	200.8	161.1	171.5	152.7
less Tax Depreciation	48.2	52.6	57.4	61.4	65.1
Closing TAB	504.6	652.8	456.5	866.7	954.3

Envestra has used the tax model developed by the ESCV to determine the TAB values set out in tables 10.1 and 10.3, which model has been incorporated into the AER PTRM. This has the advantage of ensuring that the opening TAB as at 1 January 2013 is treated in a manner that is consistent with the decisions made by the ESCV in previous regulatory periods. Envestra understands that this approach is consistent with that taken by other businesses when transitioning over to the AER's PTRM.

10.5 Value of Imputation Credits (γ or gamma)

Gamma (γ) is the factor used to adjust RTI for the value attributed to imputation credits[154]. Gamma is the product of two components, known as "the distribution rate"[155] (the proportion of created franking credits that are distributed to shareholders by attaching them to dividends) and "theta" (the value to the relevant shareholder of each franking credit that is distributed to them.

[154] The terms 'gamma', franking credits and 'value of imputation credits' are used interchangeably throughout this Access Arrangement Submission.

[155] This is also referred to as the "payout ratio"

The Australian Competition Tribunal in the *Energex/ETSA Utilities and Ergon Energy* proceedings[156] determined that (i) the appropriate distribution rate is 0.7[157] and (ii) the appropriate value for theta is 0.35. The product of these two components results in an estimate for gamma of 0.25, which is the value Envestra proposes to use to estimate the benchmark cost of tax for each year of the 2013 to 2017 Access Arrangement period.

The 0.25 value for gamma proposed in this submission is consistent with the rulings of the Australian Competition Tribunal and in all decisions made by the AER since, including the recent Final Decisions for Envestra's South Australian[158] and Queensland[159] gas networks and the AERs Draft Determination for Aurora Energy Pty Ltd.[160]

10.6 Tax Losses Carried Forward

The AER requires that Envestra determine whether there would have been any tax losses as at 1 January 2013 (i.e. the start of the 2013 to 2017 Access Arrangement period). This is because any such tax losses would need to be carried forward into the 2013 to 2017 Access Arrangement period to offset any future tax liabilities that might apply.

The ESCV 2008 Final Decision (pg. 510) shows that no tax losses were forecast to arise over the 2008 to 2012 Access Arrangement period. Envestra has therefore not included tax losses in determining its benchmark tax liability for the 2013 to 2017 Access Arrangement period.

10.7 Calculating the Cost of Tax

The cost of tax calculation, applying the approach and parameters set out in this chapter, is shown in the following table.

Table 10.4: Benchmark Cost of Tax Calculation, 2013 to 2017

$M nominal	2013	2014	2015	2016	2017
Total revenue	194.0	222.1	247.0	266.7	290.5
plus capital contributions	1.9	2.0	2.0	2.1	2.1
less opex	74.8	83.4	85.1	87.5	93.4
less depreciation	48.2	52.6	57.4	61.4	65.1
less interest	53.0	60.5	69.4	76.2	83.4
less tax losses carried forward	0	0	0	0	0
Taxable income	20.0	27.6	37.1	43.7	50.8
Tax payable	**6.0**	**8.3**	**11.1**	**13.1**	**15.2**
Value of imputation credits	1.5	2.1	2.8	3.3	3.8
Benchmark cost of tax	**4.5**	**6.2**	**8.3**	**9.8**	**11.4**

156 File Nos 2, 3 and 4 of 2010
157 *Re Application by Energex Limited* (Distribution Ratio (Gamma)) (No 3) [2010] ACompT9 24 December 2010
158 AER, *Final Decision Envestra Ltd Access arrangement proposal for the SA gas network, 1 July 2011 to 30 June 2016*, June 2011
159 AER, *Final Decision Envestra Ltd Access arrangement proposal for the Queensland gas network, 1 July 2011 to 30 June 2016*, June 2011
160 AER, *Draft Distribution Determination Aurora Energy Pty Ltd 2012-13 to 2016-17*, November 2011

11. Incentive Mechanism

11.1 Introduction

This chapter determines the efficiency gain or loss arising from the efficiency carryover mechanism (ECM) that applied in the 2008 to 2012 Access Arrangement period. The amount derived under the ECM gives rise to an additional ‘building block’ in the calculation of the total revenue amounts for the 2013 to 2017 Access Arrangement period. This chapter also explains Envestra’s reasons for not including a similar ECM to apply over the 2013 to 2017 Access Arrangement period.

11.2 Requirements of the National Gas Rules

Rule 98 of the National Gas Rules (NGR) states that:

(1) A full access arrangement may include (and the AER may require it to include) one or more incentive mechanisms to encourage efficiency in the provision of services by the service provider.

(2) An incentive mechanism may provide for carrying over increments for efficiency gains and decrements for losses of efficiency from one access arrangement period to the next.

(3) An incentive mechanism must be consistent with the revenue and pricing principles.

11.3 Requirements of the Access Arrangement

Section 7.2(a) of Envestra’s current Access Arrangement sets out the guiding principles in respect of the application of the ECM that is to apply over the 2008 to 2012 Access Arrangement period. Specifically, this section states that:

> *The incentive arrangements that are to apply to cost-related efficiencies achieved by the Service Provider, and the adjustment to preserve the incentive to meet efficient growth in demand are a combination of:*
>
> - *a tariff basket form of price control; and*
> - *the carryover that would result in the Service Provider retaining the reward associated with an efficiency-improving initiative for five years after the year in which the gain was achieved, ie. a reward (being the net amount of the efficiency gains (or losses) relating to capital and operating expenditure) earned in one year of an Access Arrangement period would be added to the Total Revenue and carried forward into the Fourth Access Arrangement period if necessary, until it has been retained by the Service Provider for a period of five years.*
>
> *There would be no claw-back of gains that have already been made (or losses that have been incurred) during the Third Access Arrangement period.*
>
> *Efficiency gains (or losses) related to capital expenditure in any year would reflect the difference between the actual expenditure and the original forecast (or benchmark) expenditure level, as follows:*

Efficiency Gain = WACC x ($Capex_t^{Forecast}$ - $Capex_t^{Actual}$)
where:

WACC is the prevailing regulatory WACC, expressed in pre-tax terms.

For operating expenditure the annual efficiency gain (or loss) in Calendar Year t would be calculated as:

Efficiency Gain = $Underspending_t$ - $Underspending_{t-1}$

where:

$Underspending_t$ = $Opex_t^{Forecast}$ - $Opex_t^{Actual}$

The costs associated with a Change in Taxes Event, complying with RoLR requirements, or the reticulation of unreticulated townships which were not included in the calculation of Reference Tariffs, will be excluded from the operation of the efficiency carryover mechanism;

Any other activity that the Service Provider and the Regulator agree to be excluded from the operation of the efficiency carryover mechanism will be so excluded;

Section 7.2(b) sets out the mechanism for carrying over efficiency gains. Specifically, this section states that:

(1) For operating expenditure, it will be assumed that the Service Provider does not achieve more than the forecast productivity gain between the penultimate and last years of the Third Access Arrangement Period. As a result, if the Service Provider makes an efficiency gain in the last year of the Third Access Arrangement Period, there would be no carryover in respect of that year. However, the operating expenditure benchmark for the Fourth Access Arrangement Period will then be higher than otherwise for the Fourth Access Arrangement Period by the amount of the efficiency gain. This would provide the Service Provider with precisely the same reward had the expenditure level in the last year been known.

For capital expenditure, it will be assumed that the actual expenditure in the last year of the Third Access Arrangement Period was equal to the forecast for that year. As a result, if the Service Provider makes an efficiency gain in the last year of the Third Access Arrangement Period, there would be no carryover in respect of that year. However, the regulatory asset base (and thus the return on assets) would be higher than otherwise over the next period. This would imply that the 'return on assets' included in the revenue benchmarks would be higher, and provide the Service Provider with precisely the same reward as the carryover had the expenditure level in the last year been known.

At the following review, the regulatory asset base would be adjusted to take account of the difference between the forecast and actual capital expenditure for the last year of the Third Access Arrangement Period.

There will be no adjustment to the original expenditure benchmarks against which the assessment of the efficiency gains in excess of the forecast would be measured, with the following exceptions (as well as the exception in clause 4 below):

(a) the carryover of cost-related efficiency gains will be calculated in a manner that takes account of any change in the scope of the activities which form the basis of the determination of the original benchmarks. Any adjustment will be made following the provision of relevant information to the Regulator and the assessment of that information by the Regulator; and

(b) actual expenditure will also be adjusted to take account of the difference between forecast and actual output. This will be done by taking into account the difference in the number of connections (compared to forecast) multiplied by the capital expenditure per connection and operating expenditure per connection.

The carryover in respect of cost-related efficiency gains will be calculated in a manner that takes account of any difference between the capital replacement works assumed in Reference Tariffs for the Third Access Arrangement Period and the works actually undertaken in the Third Access Arrangement Period.

This clause shall not be construed to mean that the Service Provider:

(a) is required to undertake the capital works; or

(b) is constrained in its discretion to determine the timing, size or nature of those capital works.

To the extent that the application of this clause results in a positive efficiency carryover at the end of the Third Access Arrangement Period, the reward earned in the Third Access Arrangement Period is to be added to the Total Revenue and carried forward into the Fourth Access Arrangement Period, until it has been retained by the Service Provider for a period of five years, in accordance with this clause.

11.4 Incentive Mechanism Outcomes for the 2008 to 2012 Access Arrangement period

The ECM applying in the 2008 to 2012 Access Arrangement period applies to both capital expenditure (capex) and operating expenditure (opex), consistent with the principles set out in section 7.2 of the current Access Arrangement. An explanation of how the capex and opex ECM has applied during the 2008 to 2012 Access Arrangement period is set out below.

11.4.1 Capex

Envestra has determined the capex carry over amounts in accordance with section 7.2(a) (3) of the current Access Arrangement. This allows Envestra to retain for a period of five years an efficiency gain or loss that is determined by multiplying the difference between benchmark and actual capex by the prevailing regulatory rate of return, expressed in pre tax terms of 7.6%.

For example, the efficiency gain calculated for 2010 (in real 2006 dollar terms as per the decision of the Essential Services Commission of Victoria) is determined as follows:

Efficiency Gain in 2010 $= \text{WACC} \times (\text{Adjusted Capex } 2010^{\text{Forecast}} - \text{Capex } 2010^{\text{Actual}})$
$= 7.6\% \times (\$68.9m - \$46.3m)$
$= \$1.7m$

Consequently, in 2010 Envestra realised a \$1.7 million (in \$2006) efficiency *gain* arising from an underspend in capex in that year. This efficiency gain of \$1.7 million is the amount that is carried forward for the next five years commencing from 2011 onwards. The capex carry-over amounts for all other years of the 2008 to 2012 Access Arrangement period are calculated in the same manner.

Importantly, section 7.2(b)(3)(A) of the current Access Arrangement requires the benchmark capex values used to determine the capex efficiency carry-over amounts to be adjusted to take into account changes in the scope of activities provided by Envestra over the 2008 to 2012 Access Arrangement period. The value of the adjustment to the capex benchmarks is determined by multiplying the difference between actual and benchmark:

- domestic and non-domestic customer connections by the approved unit rate for those connections;
- rate of mains replacement (measured in kilometres) by the approved unit rate for replacement works; and
- domestic and non-domestic meter replacements by the approved unit rate for those replacements.

The intention of the ECM is therefore to ensure that the scope (or quantity) of capital works undertaken by Envestra does not influence whether an efficiency gain or loss is achieved in any particular year. The adjustments made to the capex benchmarks based on the above are set out in figure 11.1.

Figure 11.2 provides an extract from Envestra's post-tax revenue model (PTRM) that was used for calculating the capex efficiency carry over amounts to apply over the 2013 to 2017 Access Arrangement period.

11.4.2 Opex

Envestra has determined the opex carry-over amounts in accordance with section 7.2(a) (4) of the current Access Arrangement. This allows Envestra to retain for a period of five years an efficiency gain or loss that is calculated as the difference between the underspend in opex in the relevant year with the underspend in opex in the previous year, where the underspend in opex is determined by taking the difference between benchmark and actual opex in a given year.

For example, the efficiency gain calculated for 2010 (in real 2006 dollar terms as per the decision of the Essential Services Commission of Victoria) is determined as follows:

$$\begin{aligned}\textit{Efficiency Gain in 2010} \quad &= \textit{Underspending}_t - \textit{Underspending}_{t-1} \\ &= (\textit{Opex}_t^{\ \textit{Forecast}} - \textit{Opex}_t^{\ \textit{Actual}}) - (\textit{Opex}_{t-1}^{\ \textit{Forecast}} - \textit{Opex}_{t-1}^{\ \textit{Actual}}) \\ &= (\$45.5m - \$45.1m) - (\$45.8m - \$44.8m) \\ &= \$0.4m - \$1.1m \\ &= \$\text{-}0.7m\end{aligned}$$

In 2010 Envestra realised a \$0.7 million efficiency *loss* because the opex underspend in 2010 was less than the opex underspend in 2009. The \$1.1 million efficiency *loss* is the carry-over amount which is carried forward for the next five years commencing 2011 onwards. The opex carry-over amounts for all other years of the 2008 to 2012 Access Arrangement period are calculated in the same manner, aside from in 2008 where the value of $\textit{Underspending}_{t-1}$ is set at zero.

As with capex, section 7.2(b)(3)(A) of the Access Arrangement requires the benchmark opex values used to determine the opex efficiency carry-over amounts to be adjusted to take into account changes in the scope of activities provided by Envestra over the 2008 to 2012 Access Arrangement period. The adjustment is determined by multiplying the difference between actual and benchmark domestic and non-domestic customer connections by the approved unit rate for those connections (see figure 11.3).

Figure 11.1: Required Adjustments to Capex Benchmarks

CAPITAL EXPENDITURE					
Benchmark Adjustment for Growth	**2008**	**2009**	**2010**	**2011**	**2012**
Domestic					
Capital expenditure per connection	$ 1,452.00	$ 1,482.00	$ 1,512.00	$ 1,542.00	$ 1,572.00
Adjustments to Capex Benchmark $m (1/7/06)	0.595	1.060	4.194	4.729	2.400
Non Domestic					
Capital expenditure per connection	$ 4,523.00	$ 4,610.00	$ 4,815.00	$ 4,955.00	$ 5,043.00
Adjustments to Capex Benchmark $m (1/7/06)	-1.565	-1.710	-2.393	-2.512	-2.603
Adjustments to Capex Benchmark $m (1/7/06)	**-0.97**	**-0.65**	**1.80**	**2.22**	**-0.20**
Benchmark Adjustment for LP replacement program					
Forecast km replaced	90.0	100.0	110.0	120.0	150.0
Actual / Forecast km replaced	42.8	13.0	45.2	100.3	150.0
	-47.2	-87.0	-64.8	-19.7	0.0
Capital Expenditure per metre	146.02	146.02	146.02	146.02	146.02
Adjustments to Capex Benchmark $m (1/7/06)	**-6.890**	**-12.703**	**-9.461**	**-2.872**	**0.000**
Benchmark Adjustment for Meter Replacement	**2008**	**2009**	**2010**	**2011**	**2012**
Domestic					
Forecast Number of replacements	32,604	37,145	35,453	21,920	19,140
Actual / Forecast Number of new replacements	19,652	12,364	21,459	26,824	26,824
	-12,952	-24,781	-13,994	4,904	7,684
Non Domestic					
Forecast Number of replacements	1,356	1,126	1,054	1,105	1,188
Actual / Forecast Number of new replacements	509	454	468	480	478
	-847	-672	-586	-625	-710
Domestic					
Capital expenditure per meter	$ 126.00	$ 128.00	$ 131.00	$ 134.00	$ 136.00
Adjustments to Capex Benchmark $m (1/7/06)	-1.632	-3.172	-1.833	0.657	1.045
Non Domestic					
Capital expenditure per meter	$ 939.00	$ 958.00	$ 977.00	$ 997.00	$ 1,017.00
Adjustments to Capex Benchmark $m (1/7/06)	-0.795	-0.644	-0.573	-0.623	-0.722
Adjustments to Capex Benchmark $m (1/7/06)	**-2.43**	**-3.82**	**-2.41**	**0.03**	**0.32**

Figure 11.2: Determination of Capex Related Efficiency Carryover Amounts

CAPITAL EXPENDITURE	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Capex Benchmark $m (1/1/01)										
Capex Benchmark $m (1/7/06)	70.6	83.4	79.0	69.1	79.7					
Adjustments to Capex $m (1/7/06)	(10.3)	(17.2)	(10.1)	(0.6)	0.1					
Adjusted Capex Benchmark $m (1/7/06)	60.3	66.2	68.9	68.5	79.8					
Capex Actual $m (MOD)	48.5	42.7	52.1	71.2						
Capex Actual $m (1/7/06)	45.8	38.4	46.3	61.5	79.8					
Capex Underspend $m (1/7/06)	14.5	27.8	22.6	7.0	-					
Capex Incremental Gain $m (1/7/06)	1.1	2.1	1.7	0.5	-					
Carry-Over - Year 2013		1.1	1.1	1.1	1.1	1.1				
Carry-Over - Year 2014			2.1	2.1	2.1	2.1	2.1			
Carry-Over - Year 2015				1.7	1.7	1.7	1.7	1.7		
Carry-Over - Year 2016					0.5	0.5	0.5	0.5	0.5	
Carry-Over - Year 2017						-	-	-	-	-
Capex Efficiency Carry-Over $m (1/7/06)						**5.5**	**4.4**	**2.3**	**0.5**	-

Figure 11.3: Required Adjustments to Opex Benchmarks

OPERATING EXPENDITURE Benchmark Adjustment for Growth	2008	2009	2010	2011	2012
Domestic					
Forecast Number of new connections	13,247	14,084	14,459	14,334	13,122
Actual / Forecast Number of new connections	13,657	14,799	17,233	17,401	14,649
	410	715	2,774	3,067	1,527
Non Domestic					
Forecast Number of new connections	707	704	816	869	854
Actual / Forecast Number of new connections	361	333	319	362	338
	-346	-371	-497	-507	-516
Domestic					
Operating Expenditure per connection	$ 17.00	$ 17.05	$ 17.11	$ 17.16	$ 17.22
Adjustments to O&M Benchmark $m (1/7/06)	0.007	0.019	0.067	0.120	0.146
Non Domestic					
Operating Expenditure per connection	$ 17.00	$ 17.05	$ 17.11	$ 17.16	$ 17.22
Adjustments to O&M Benchmark $m (1/7/06)	-0.006	-0.012	-0.021	-0.030	-0.039
Total Adjustments to O&M Benchmark $m (1/7/06)	**0.001**	**0.007**	**0.046**	**0.090**	**0.108**

Figure 11.4 provides an extract from the PTRM that was used for calculating the opex efficiency carry over amounts to apply over the 2013 to 2017 Access Arrangement period.

Figure 11.4: Determination of Opex Related Efficiency Carryover Amounts

OPERATING EXPENDITURE	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
O&M Benchmark $m (1/1/01)										
O&M Benchmark $m (1/7/06)	44.1	45.8	45.4	45.8	46.6					
Adjustments to O&M $m (1/7/06)	0.0	0.0	0.0	0.1	0.1					
Adjusted O&M Benchmark $m (1/7/06)	44.1	45.8	45.5	45.9	46.7					
O&M Actual $m (MOD)	45.9	49.1	50.8	54.9						
O&M Actual $m (1/7/06)	43.3	44.2	45.1	47.4	46.7					
O&M Underspend $m (1/7/06)	0.7	1.6	0.3	(1.5)	(1.5)					
O&M Incremental Gain $m (1/7/06)	0.7	0.9	(1.3)	(1.8)	-					
Carry-Over - Year 2008		0.7	0.7	0.7	0.7	0.7				
Carry-Over - Year 2009			0.9	0.9	0.9	0.9	0.9			
Carry-Over - Year 2010				(1.3)	(1.3)	(1.3)	(1.3)	(1.3)		
Carry-Over - Year 2011					(1.8)	(1.8)	(1.8)	(1.8)	(1.8)	
Carry-Over - Year 2012						-	-	-	-	-
O&M Efficiency Carry-Over $m (1/7/06)						**(1.5)**	**(2.2)**	**(3.1)**	**(1.8)**	-

11.4.3 Combined Capex and Opex Carry-Over Amount

Figure 11.5 show the carry over amounts to apply in the 2013 to 2017 Access Arrangement period. The total efficiency gain or loss to apply from 2013 is determined as the sum of the total capex efficiency and total opex efficiency for a given year. For example, the total efficiency carry-over amount for 2013 is $4.0 million, which is the sum of the total capex efficiency gain of $5.5 million less the total opex efficiency loss of $1.5 million.

Figure 11.5 shows the resultant total carry-over amounts that are added to the 'building blocks' used to determine Total Revenue in the 2013 to 2017 Access Arrangement period.

Figure 11.5: Total Carry-over Building Block

	2013	2014	2015	2016	2017
Total Efficiency Carry-Over $m (1/7/06)	4.0	2.1	(0.9)	(1.3)	-

11.5 Proposed Incentive Mechanism for the 2013 to 2017 Access Arrangement period

Envestra has elected not to include an incentive mechanism to apply in the 2013 to 2017 Access Arrangement period. This is because our outsourcing contract with the APA Group already contains efficiency incentives, which are payable to APA for achieving reductions in the costs of new connections and reductions in controllable costs per GJ.

The connection cost incentive payment is payable where the average capital cost of connecting new customer sites to the networks in a financial year is less than the average capital cost of connecting new customer sites to the networks in the prior financial year. The controllable cost per gigajoule incentive payment is payable where operating costs per gigajoule in a financial year are less than the costs for the preceding year.[161]

The purpose of the incentive payments is to drive APA to achieve lower costs (which lower costs ultimately benefit consumers). Mr Ferguson, APA's Group Manager Networks, noted in his affidavit that the incentive payments are a very significant driver of the relationship between Envestra and APA[162]. Mr Ferguson's affidavit notes that incentive payments have been made by Envestra in all years over the past 10 years.[163]

The evidence regarding Envestra's past performance suggest that the incentive mechanisms are effective in contributing to Envestra achieving efficient cost outcomes. In particular, Envestra has achieved reductions in operating costs per customer of 43% since 1998 (see section 5.8). Moreover, expert evidence provided as part of this Access Arrangement Information demonstrates that Envestra's productivity levels are consistent with good industry practice (see sections 3.7 and 5.7).

Envestra is also focused on the incentive payments in the operating agreement (and not the ECM) as the primary driver of efficiency improvements.

Envestra therefore does not consider that additional efficiency incentives to that which have already been included in its operating agreement with APA since 1999 should be applied. This position is consistent with the decisions made by the AER for Envestra's Wagga Wagga gas network, Jemena's New South Wales gas network and most recently for APA's Queensland gas network.

161 See chapter 5 for further discussion on the efficiency incentives included in the 2007 Operating and Management Agreement with APA.
162 Affidavit of John Ferguson, paragraph 72.
163 Affidavit of John Ferguson, paragraph 77.

12. Total Revenue

12.1 Introduction

The proceeding chapters of this Access Arrangement Information (AAI) have set out the various components that comprise the total revenue requirement that Envestra is allowed to recover over the 2013 to 2017 Access Arrangement period. This chapter sets out the total revenue requirements and translates that revenue into a price path to apply over the regulatory period.

12.2 Requirements of the National Gas Rules

Rule 76 of the National Gas Rules (NGR) requires that total revenue is to be determined for each regulatory year using the building block approach, in which the building blocks are:

- a return on the projected capital base for the year;
- depreciation of the projected capital base for the year;
- a forecast of operating expenditure for the year;
- any increments or decrements for the year resulting from the operation of an incentive mechanism to encourage gains in efficiency; and
- a forecast of the cost of tax (set out in chapter 10).

Rule 92(2) requires that the present value of the total revenue determined from the building block equal the present value of the total revenue derived from the proposed Reference Tariffs.

12.3 Ancillary Reference Service Revenue

In determining building block revenue, account needs to be taken of revenue derived from Ancillary Reference Services (which are set out in section 4.4). The demand for Ancillary Reference Services (ARS) is shown in table 12.1 and the associated forecast revenue is shown in table 12.2. The demand for some of these services is static, while for others the demand increases with the projected increase in the customer base.

Table 12.1: Forecast Demand for Ancillary Reference Services, 2013 to 2017

ARS Demand	2013	2014	2015	2016	2017
Meter and Gas Installation Test	76	76	76	76	76
Disconnection	7,101	7,101	7,101	7,101	7,101
Reconnection	6,648	6,648	6,648	6,648	6,648
Meter Removal	1,850	1,850	1,850	1,850	1,850
Meter Reinstallation	148	148	148	148	148
Special Meter Read Metro	108,664	111,349	114,100	116,919	119,808
Special Meter Read Non-metro	31,724	32,508	33,311	34,134	34,977

Table 12.2: Forecast Revenue from Ancillary Services, 2013 to 2017

Revenue Forecast $m 2011	2013	2014	2015	2016	2017
Meter and Gas Installation Test	0.01	0.01	0.01	0.01	0.01
Disconnection	0.43	0.43	0.43	0.43	0.43
Reconnection	0.47	0.47	0.47	0.47	0.47
Meter Removal	0.16	0.16	0.16	0.16	0.16
Meter Reinstallation	0.01	0.01	0.01	0.01	0.01
Special Meter Read Metro	0.86	0.88	0.90	0.92	0.95
Special Meter Read Non-metro	0.33	0.34	0.35	0.36	0.37
Total ARS Revenue	**2.29**	**2.31**	**2.34**	**2.38**	**2.41**

12.4 Building Block Revenue

This AAI has set out the derivation of all the relevant building blocks to determine total revenue, aside from the return on capital building block. This is determined by multiplying the weighted average cost of capital of 9.06% (see chapter 9) by the opening capital base in each year of the 2013 to 2017 Access Arrangement period (see chapter 8). The total building block revenue for each year of the 2013 to 2017 Access Arrangement period is set out in table 12.3.

Table 12.3: Building Block Revenue, 2013 to 2017

$m Nominal	2013	2014	2015	2016	2017
Return on capital	101.2	115.6	132.6	145.6	159.2
Return of capital	13.6	17.0	20.9	23.8	26.5
Opex	69.9	80.7	86.3	89.2	93.4
Efficiency Carry-over amounts	4.9	2.7	-1.1	-1.7	0.0
Cost of Tax	4.5	6.2	8.3	9.8	11.4
Total Building Block Revenue (incl. ARS)	**194.0**	**222.1**	**247.0**	**266.7**	**290.5**
less Ancillary Reference Service	2.4	2.5	2.6	2.7	2.8
Total Building Block Revenue (excl. ARS)	**191.6**	**219.7**	**244.4**	**264.0**	**287.7**

Note: Opex includes Liquidity Costs and Debt Raising Costs

Envestra has then specified a price path for its Reference Services to “smooth” its revenue recovered from Reference Tariffs over the 2013 to 2017 Access Arrangement period. This is achieved by setting the present value of the revenue to be recovered from Reference Tariffs equal to the present value of the building block revenue.

This “smoothing” of revenue gives rise to a series of percentage changes (or X factors) setting out how Reference Tariffs in each year need to change for the above equilibrium to be achieved. This results in an X factor of -14.4% in 2013, then an X factor of -12.3% in 2014 followed by X factors of -7.3% in every year thereafter (where a negative X factor results in a positive percentage increase in Reference Tariffs by virtue of the Tariff Control Formula set out in box 15.1 of chapter 15.

Table 12.4: Proposed Price Path

Cost & Revenue Alignment ($m Nominal)	2013	2014	2015	2016	2017	NPV
Total Building Block Revenue (excl. ARS) - Unsmoothed	191.6	219.7	244.4	264.1	287.7	921.9
Total Reference Tariff Revenue - Smoothed	192.4	220.1	240.9	264.1	290.2	921.9
Price Path	-14.4%	-12.3%	-7.3%	-7.3%	-7.3%	

Envestra has adopted this price path in order to equate the “unsmoothed” building block revenue and the “smoothed” reference tariff revenue in 2017. This will ensure that there is no one-off adjustment to tariffs (either positive or negative) required in the 2018 to 2022 Access Arrangement period to simply equate tariff revenue with underlying costs (represented by the building block revenue).

Part C – Derivation of Reference Tariffs

13. Demand Forecasts

13.1 Introduction

This chapter explains how Envestra has forecast customer numbers, volume and Maximum Hourly Quantity (MHQ) for the 2013 to 2017 Access Arrangement period. The demand and customer number forecasts drive parts of the capital and operating expenditure requirements into the future. The forecasts are also a key input into determining Reference Tariffs.

This chapter firstly sets out trends in consumption over the past 10 years. This shows that Envestra has not achieved the aggressive benchmarks set for the volume (Tariff V) market, which comprises residential and commercial/small industrial (non-residential) connections and contributes approximately 98% of total revenue. The analysis also shows Envestra has experienced a continual decline in Tariff V consumption over the past 10 years.

It is against this background that Envestra has prepared its demand forecasts. In doing so, Envestra has sought independent and expert advice from Core Energy. The demand forecasts include the impact of Envestra's network development and network expansion programs proposed to occur over the 2013 to 2017 Access Arrangement period (see chapters 6 and 7).

Simply put, Envestra's forecasts reflect a continuation of the trend decline in consumption augmented by the forecast changes to the retail gas prices to occur over the upcoming period. The projected retail gas price is forecast to be higher than historic levels due to the following three factors:

(1) *Introduction of the Clean Energy Legislation* – customers will for the first time be exposed to a price on carbon emissions from 1 July 2012. Commonwealth Treasury modeling indicates an expected increase to residential retail gas prices of 9%[164].

(2) *Increases in the wholesale gas prices* – the construction of Queensland's Liquefied Natural Gas (LNG) export terminals will expose Australian East Coast gas prices to a world price for the first time. Commonwealth Treasury modeling indicates a 15% increase to the wholesale gas prices to 2017 as a result of export parity pricing.

(3) *Increases to Envestra network charges* – stemming primarily from uplifts to capital expenditure, mainly driven by the mains replacement program (MRP) agreed with Energy Safe Victoria (ESV).

The above approach to developing the demand forecasts for each of the market segments in Victoria is consistent with the approach approved by the AER for Envestra's South Australian and Queensland networks. It is also consistent with the approach proposed to apply for Envestra's Albury network over the 2013 to 2017 Access Arrangement period.

13.2 Requirements of the National Gas Rules

Rule 74 of the National Gas Rules is the relevant rule applicable to the demand forecast. Rule 74 requires:

[164] Commonwealth Treasury Strong Growth, Low Pollution – Modelling a Carbon price; July 2011 Table 5.19 page 137

(1) Information in the nature of a forecast or estimate must be supported by a statement of the basis of the forecast or estimate.

(2) A forecast or estimate:

 (a) must be arrived at on a reasonable basis; and

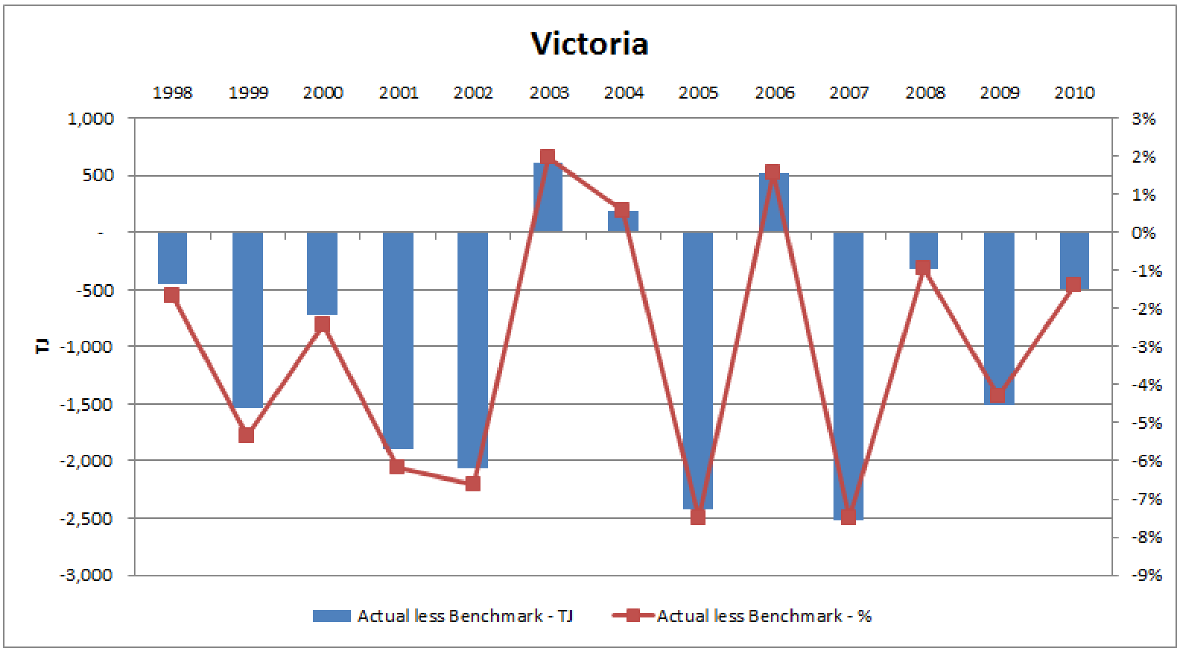
 (b) must represent the best forecast or estimate possible in the circumstances.

13.3 Past Performance

Envestra has fallen below the benchmark volumes set by the Regulator for the Tariff V segment in ten of the last thirteen years, having only marginally exceeded benchmark volumes on three occasions. This reflects, in part, the difficulty in forecasting volumes given the uncertainty surrounding the impact of factors affecting gas sales (particularly the impact of weather and government policy).

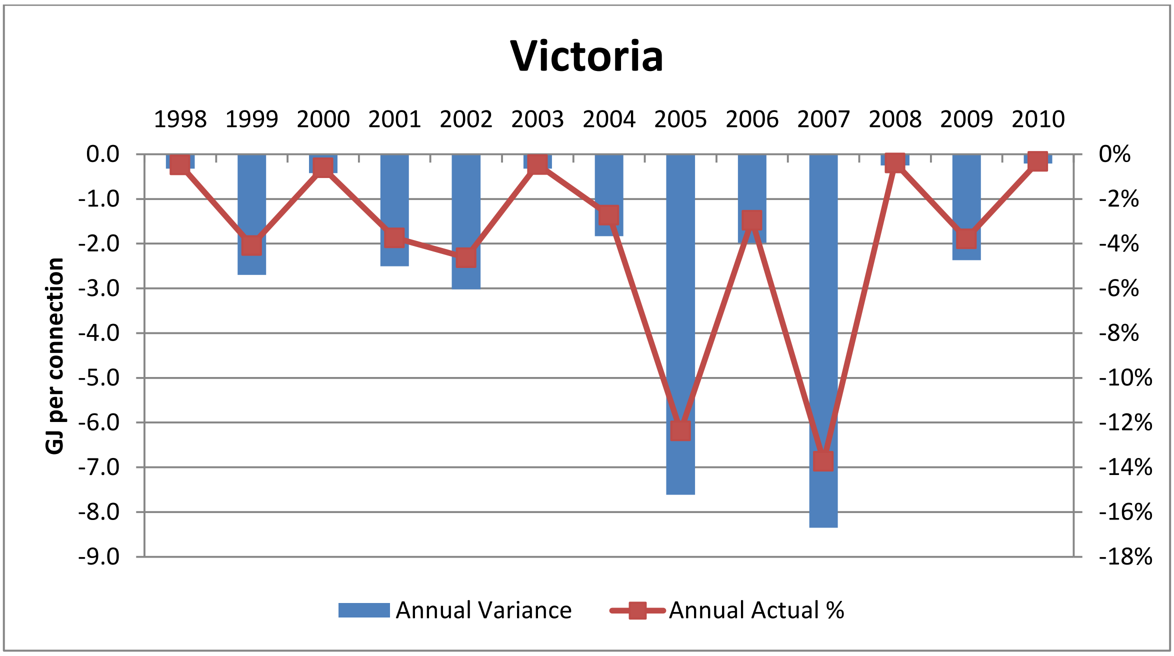
Figure 13.1 shows the difference between actual and benchmark volumes for the Tarff V segment between 1998 (when regulatory benchmarks were first set) and 2010. This shows that, on average, actual volumes have been 3% lower than the benchmark volumes set by the Regulator.

Figure 13.1: Actual less Benchmark Volumes for Tariff V Connections, 1998 to 2010



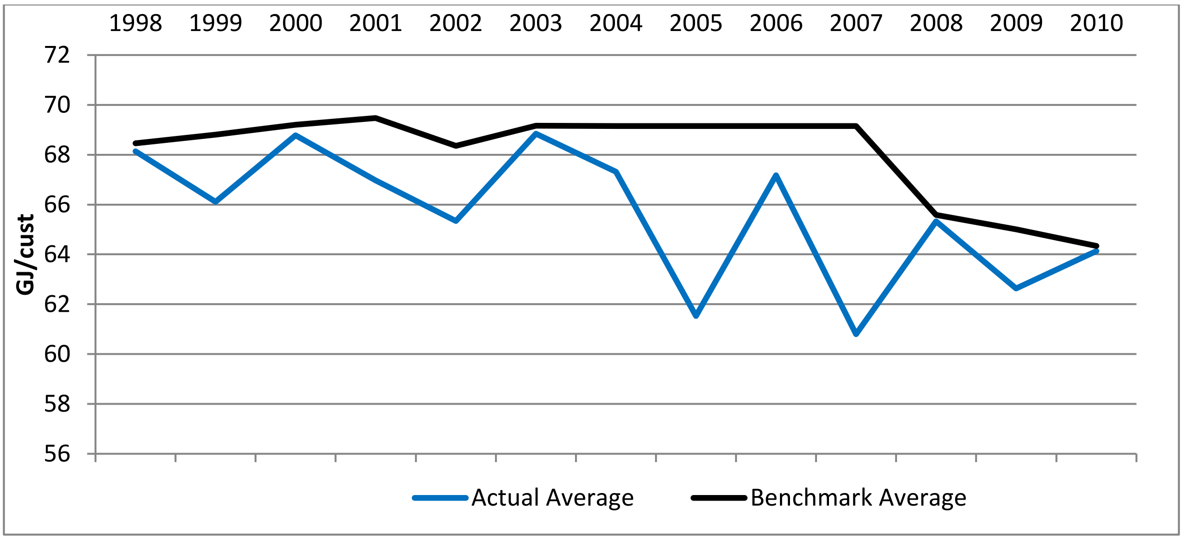
The primary reason explaining this ongoing gap between actual and benchmark volumes is that average consumption has been lower, and has fallen at a faster rate, than that forecast by the Regulator (see figure 13.2). Between 1998 and 2010, consumption per connection was on average 4% lower than benchmark levels. Actual average consumption did not exceed benchmark on any occasion over the last thirteen years.

Figure 13.2: Actual less Benchmark Average Consumption for Tariff V Connections, 1998 to 2010



The data shows that there has been a long term trend towards declining average consumption for residential and commercial connections (see figure 13.3). Average consumption has fallen from 68 gigajoules per annum (GJ/pa) in 1998 to 64 GJ/pa in 2010, reflecting an average annual decline of 0.5%. This decline has predominantly occurred in the last five years and has declined at a rate faster than forecast by the Regulator. These trends are also apparent in Envestra's South Australian and Queensland networks.

Figure 13.3: Actual and Benchmark Tariff V Average Consumption, 1998 to 2010



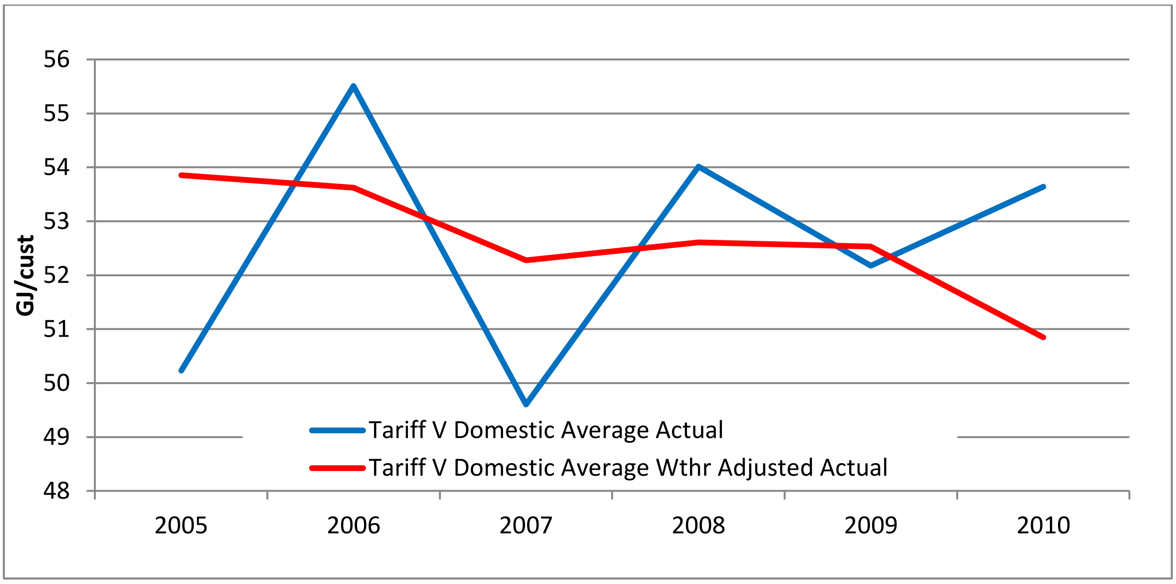
Tariff V is made up of the residential and non-residential (commercial and small industrial) customer segments. Envestra has historically applied the same tariff to both market segments. As part of the revisions to the 2013 to 2017 Access Arrangement, Envestra is proposing the introduction of separate tariffs to apply to each market segment to better match the usage profile of each customer (refer chapter 14 for further discussion).

The allocation of each customer to either residential or non-residential is predicated on the retailers' classification, which classification is obtained by Envestra when a service connection request is lodged. The following section details the decline that has occurred in the residential segment since 2005. The decline in residential consumption warrants particular attention as it comprises almost 90% of Envestra's annual revenue recovery.

13.3.1 Historic Residential Demand

The figure below shows the residential average consumption since 2005 in actual and weather adjusted terms. It clearly demonstrates the relationship between gas consumption and weather (2006, 2008 and 2010 being colder years than 2005, 2007 and 2009). Once the effects of weather are removed (refer section 13.4.2 and attachment 13.1 for a description of this process), the underlying trend decline is revealed. This shows that the underlying trend decline in average annual consumption has been 1% since 2005.

Figure 13.4: Actual and Weather Adjusted Actual Residential Average Consumption, 2005 to 2010



There are a range of factors contributing to the decline in average consumption per connection, many of which have strengthened their contribution to reducing average consumption over the more recent period. These factors include (but are not limited to):

- Government policy – policy is increasingly focused at initiatives that reduce energy consumption or distort preferences towards appliances that are less greenhouse intensive (such as solar hot water). Victorian government policy requires new homes to install either a solar hot water unit or a rainwater tank. Customer preference has been for the installation solar hot water units;

- warmer weather – average temperatures in Victoria have increased by approximately 0.31°C per decade since 1950[165];

- increased penetration of reverse cycle air conditioners (RCA) – Australian Bureau of Statistics (ABS) data[166] ABS 4602.0.55.001 shows that RCA penetration increased by 7% between 2005 and 2011 while gas heating declined by 4% over the same period;

[165] Suppiah, R and Whetton, P. Projected changes in temperature and heating degree-days for Melbourne, 2012-17

- increased appliance efficiency – the appliance efficiency requirements set out in the Minimum Energy Performance Standards (MEPS) scheme have continued to increase;

- Mandatory Renewable Energy Target (MRET) – a national scheme requiring energy retailers to purchase electricity from renewable sources. This obligation is met by retailers acquiring Renewable Energy Certificates (REC) from certified renewable energy producers. RECs can be obtained from large scale renewable generators such as wind farms or small scale appliances such as residential solar hot water units;

- Water Efficiency Labelling Scheme (WELS) – Akin to energy labelling, WELS enables consumers to compare appliances based on water efficiency. Water efficient appliances impact on gas demand as a result of the reduced requirement for hot water;

- Victorian Energy Efficiency Target – Victorian Government scheme which requires energy retailers to engage with residential customers to minimise energy use within existing dwellings;

- Connection of new customers – customers in new homes consume less on average than customers in existing homes (for example, because new homes have more energy efficient building design and appliances); and

- Dwelling type – Victoria is undergoing a shift in the type of dwellings being constructed from traditional detached dwellings to multi-unit developments[167].

With regard to the last two points, the lower average consumption of newer customers is attributable to factors such as fewer gas appliances per dwelling (such as gas heating) and those appliances being more efficient, particularly gas hot water which is nearly all solar boosted. Further, dwelling construction type in Victoria is shifting from detached homes to multiunit developments, which are smaller in size and therefore require less gas for space heating etc.

Figure 13.5 demonstrates the effect these changes in consumer preferences towards appliance and dwelling type are having on average consumption. The figure clearly shows that newer homes are consuming progressively less per connection. For example, a new customer connection in 2009 consumed around 50 GJ/pa in 2010 while a new customer connected in 2005 consumed around 58 GJ/pa in 2010, reflecting a reduction in average consumption of 14% over the past four years.

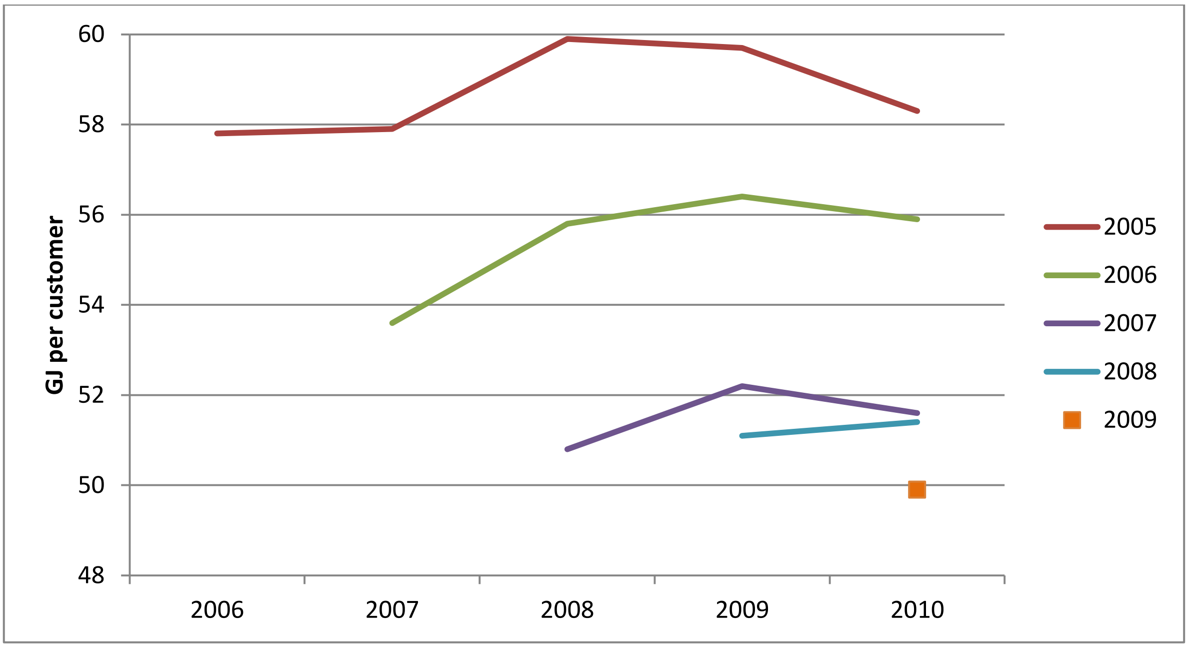
Envestra considers government policy initiatives aimed at reducing energy consumption are most likely to be strengthened over the 2013 to 2017 Access Arrangement period. The introduction of a carbon price, along with continued federal and state government policies in support of direct measures (such as rebates and minimum efficiency standards) reflects the increased focus on reducing the nation's carbon footprint.

However, the continually evolving policy environment highlights the difficulty in forecasting volumes. For example, in some cases historic data might not be available to base a forecast where the policy has been recently introduced. Likewise, it is not possible to reliably forecast future changes to the current energy policy environment. This makes it difficult for businesses to substantiate reasons for volumes to fall at rates above trend levels, as has occurred over the 2008 to 2012 Access Arrangement period.

166 ABS Catalogue Number 4602.0.55.001 - Environmental Issues: Energy Use and Conservation, March 2011

167 Refer section 13.5.1 below for further discussion.

Figure 13.5: Actual Average Residential Consumption by Year of Installation, 2005 to 2010



That said, what is clear is that the trend rate of decline in average consumption for residential connections shows no sign of abatement and will accelerate over the 2013 to 2017 Access Arrangement period in response to retail gas price increases, continued government policy initiatives (including the introduction of the six star building standard) and changing consumer preferences for the type of dwelling and the appliances used in them.

In response to these concerns, Envestra engaged Core Energy to provide it with independent and expert advice on forecast customer numbers and volumes for the 2013 to 2017 Access Arrangement period. The remainder of this chapter explains in more detail the Core Energy methodology and the resultant forecasts of volumes, customer numbers and demand to apply over the 2008 to 2012 Access Arrangement period.

13.4 Core Energy Forecasting Approach

Core Energy was engaged to forecast customer numbers and volume across Envestra's networks by customer type. This section describes the approach taken by Core Energy to prepare these forecasts and the key drivers that influenced the forecasts (the Core Energy report is provided as attachment 13.1).

13.4.1 Forecasting Approach

The following outlines Core Energy's approach to modeling Envestra's demand forecast.

(1) Obtain actual annual and monthly data from 2005 to 2010 for residential and non-residential Tariff V customers and Tariff D customers (which reflects the period whereby residential Tariff V data are available);

(2) Determine the sensitivity between historic gas consumption and weather to determine the weather normalised historic data;

(3) Run regression analyses testing various drivers against gas demand per connection. Significant correlations were found for:

   (a) Residential Tariff V - Retail Gas Price, Gross Household Disposable Income (GHDI) and underlying trend decline

   (b) Non-residential Tariff V and Tariff D - Retail Gas Price, Gross State Product (GSP) and underlying trend decline

(4) Run regression analyses testing various drivers against customer numbers. Significant correlations were found for:

   (a) Residential Tariff V - dwelling starts;

   (b) Non-residential Tariff V and Tariff D - underlying trend decline and GSP

(5) Developed model based on these regression outcomes to derive final demand forecasts.

The approach utilised by Core Energy is consistent with the approach accepted by the AER in respect of Envestra's South Australian and Queensland networks for the 2011/12 to 2015/16 Access Arrangement period.[168] This approach involves adjusting the observed trend decline in average consumption for the effects of factors not included in the historic trend, such as changes in retail gas prices driven by the introduction of the carbon price and changes in Envestra's network prices.

The approach adopted by Core Energy has enabled Envestra to provide the AER with a detailed model clearly demonstrating how the demand forecasts were determined for each customer segment (see attachment 13.2). This level of transparency, which has not been provided by Envestra in past reviews, allows the AER to clearly understand and test the drivers of changes in volume over the 2013 to 2017 Access Arrangement period.

Table 13.1 sets out the nature of the forecasts that Core Energy has prepared for each zone on Envestra's network. The forecasts prepared by Core Energy reflect the manner by which each customer group is billed. For example, forecasts of MHQ are not required for residential customers as this group is charged based on the volume of gas used. This information therefore reflects that required by the AER's post-tax revenue model (PTRM) to forecast regulatory revenue from distribution tariffs over the 2013 to 2017 Access Arrangement period.

Table 13.1: Forecast prepared by Core Energy

	Customer Numbers	Volume	Maximum Daily Quantity
Residential Tariff V	✓	✓	Not Required
Non-Residential Tariff V	✓	✓	Not Required
Demand Tariff D	✓	✓	✓

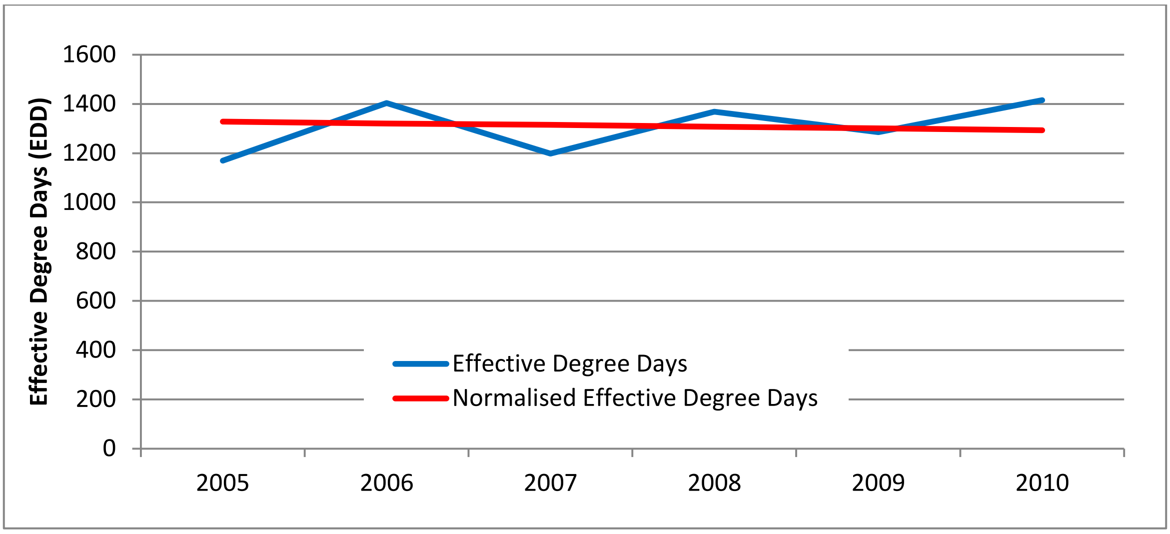
These forecasts are produced for each of the Central, North, Murray Valley (Vic) and Bairnsdale zones.

[168] AER Final Decision Access Arrangement proposal for the SA gas network June 2011, pages 102-3

13.4.2 Weather Normalisation and Climate Change

Core Energy weather normalised the historic gas consumption data using actual effective degree days (EDD) obtained from AEMO and baseline EDD from CSIRO[169]. The EDD formula was taken from the AEMO "Retail Market Procedures (Victoria)" and utilises 8 three hourly readings from the Bureau of Meteorology's Melbourne Station from 3am to 12pm (EDD_{312}). EDD_{312} was found to be the most accurate of the different EDD formula tested by AEMO in its review of EDD in 2009[170]. The chart below shows the actual and baseline EDD from 2005 to 2010.

Figure 13.6: Actual vs Baseline EDD, 2005 to 2010



CSIRO developed the baseline EDD by correlating historic EDD with temperature for the period 1970 to 2005. The baseline EDD was calculated by applying the observed historic relationship between temperature and EDD to CSIRO's projected temperatures to 2017, which forecast temperatures utilise the United Nation's Intergovernmental Panel on Climate Change (IPCC) Special Report on Emission Scenarios (SRES). A full detailed explanation of CSIRO's methodology is provided as attachments 13.2[171] and 13.3[172].

The baseline EDD obtained from CSIRO demonstrates the ongoing impact of global warming, which baseline is declining at a rate of approximately 8 EDD per year. The warming trend also helps to explain the shift in consumer preferences from gas heating to electric RAC units that can heat and cool.

Core Energy used regression analysis to estimate the sensitivity of each tariff segment to non-baseline EDD, which sensitivity is given in the table 13.2.

[169] Suppiah, R and Whetton, P. Projected changes in temperature and heating degree-days for Melbourne, 2012-17, Table 3 Urban Heat Island growth plus average greenhouse warming (UHI+agw), February 2012

[170] 2009 AEMO Review of Weather Standards for Gas Forecasting

[171] Suppiah, R and Whetton, P. Projected changes in temperature and heating degree-days for Melbourne, 2012-17, February 2012

[172] Suppiah, R and Whetton, P. Projected changes in temperature and heating degree-days for Melbourne, 2008-12, March 2006

Table 13.2: Sensitivity – GJ per connection per non baseline EDD

	Sensitivity GJ/Connection/EDD
Residential Tariff V	0.02
Non-Residential Tariff V	0.07
Demand Tariff D	2.20

Chapter 2 of Core Energy's report (refer attachment 13.1) describes the methodology and outcomes of the weather normalisation in further detail.

13.4.3 Price Elasticity

Projected retail gas prices impact on gas demand through application of a measure of price elasticity. Core Energy utilised the lagged long term price elasticity consistent with that applied in Envestra's South Australian and Queensland regulatory decisions of -0.3 for residential customers and -0.35 for non-residential customers. The AER found these elasticties to be reasonable as they fell within a range of values observed by the AER[173].

Core Energy also calculated a short run price elasticity (i.e. a single year effect) based on Envestra's Victorian data, which analysis determined a price elasticity of -0.274 for residential customers and -0.273 for non-residential customers. This analysis confirms the inverse relationship between gas price and gas consumption and the appropriateness of the previously applied long term elasticities of -0.3 for residential customers and -0.35 for non-residential customers.

Chapter 5 of Core Energy's report (attachment 13.1) describes the methodology and outcomes of the price elasticity analysis in further detail.

13.5 Residential Tariff V Forecasts

The key drivers of the residential sales forecasts are:

(1) customer numbers; and

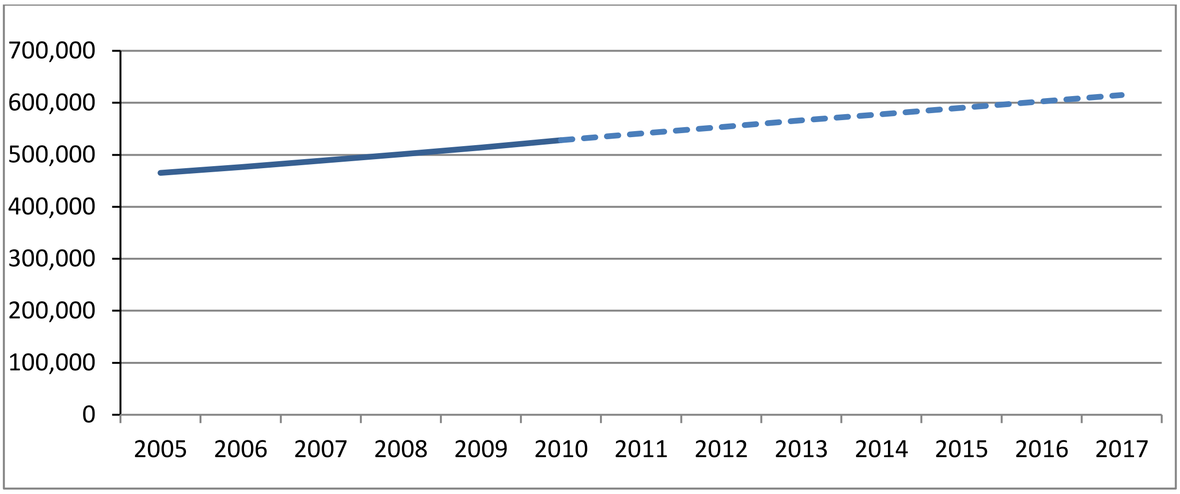
(2) average consumption.

13.5.1 Customer Numbers

Envestra's customer numbers are projected to grow at 2.1% per annum to 2017, which is marginally lower than the 2.5% per annum growth experienced by Envestra since 2005. The forecast is a combination of Core Energy's customer number forecast (derived from the Housing Industry Associations' (HIA) dwelling stock forecast) and the incremental impacts of Envestra's proposed network development (see attachment 6.3) and network expansion programs (see business case V100).

173 AER Final Decision Access Arrangement proposal for the SA gas network June 2011, pages 102-3

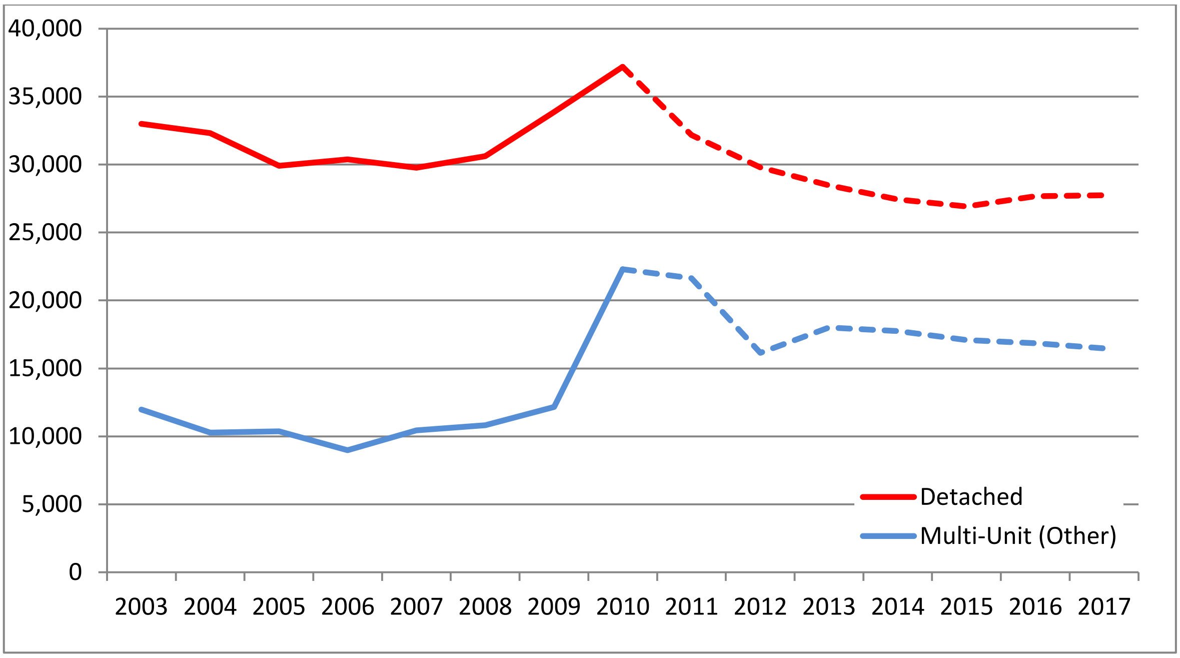
Figure 13.7: Residential Customer Number Forecast



The HIA provided the dwelling start forecasts used to underpin the residential customer number projection. The HIA provides a forecast to 2017 of dwelling starts for detached (house and townhouse) and other (multi-unit) dwellings. Victoria averaged dwelling starts of approximately 41,000 per annum during the period 2003 to 2008. From 2009 to 2011 dwelling starts increased from 46,000 in 2009 to 59,000 in 2010 before falling again to 54,000 in 2011. The pace of growth in those three years exceeded underlying required housing stock levels and hence the HIA forecast a return to lower dwellings starts of 45,000 per annum, albeit still some 10% above 2003 to 2008 levels.

An important aspect of the housing starts is the mix between detached and multi-unit has changed, with the proportion of new dwellings being multi-unit lifting from 25% to 38% over the 2012 to 2017 period. This reflects the actual change that has occurred during the period 2009 to 2011. This will have a negative affect on Envestra's forecast consumption as apartments either do not have gas connected or use less gas than a traditional detached dwelling due to smaller floor areas.

Figure 13.8: Dwelling Start Forecast

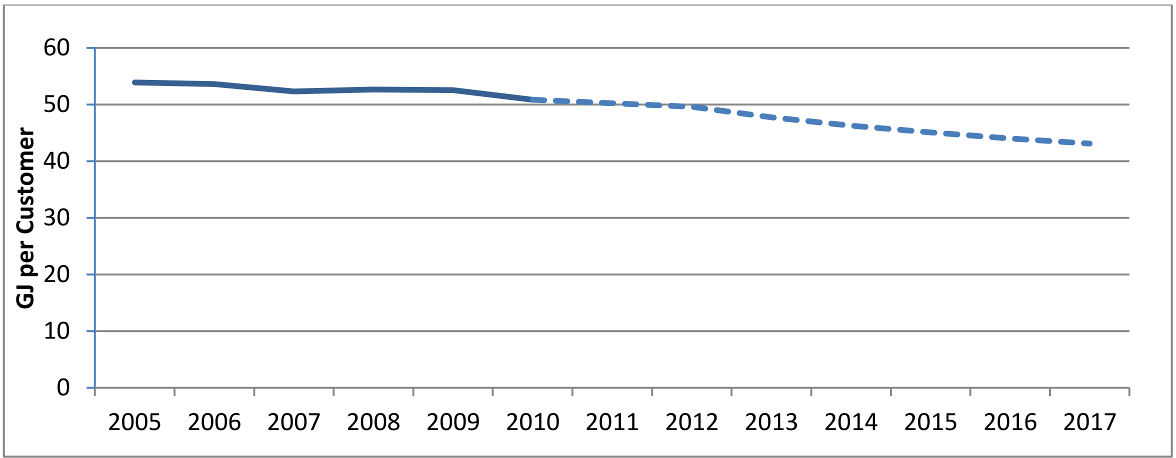


13.5.2 Average Consumption

Envestra's residential average consumption is projected to decline by 2.9% per annum over the 2013 to 2017 Access Arrangement period. The forecast decline is made up of the historic trend decline of 1%, introduction of the six star building standard, the impact of retail gas price increases due to the introduction of the carbon tax, wholesale gas price increases and network price increases. As with customer numbers, average consumption is a combination of Core Energy's average consumption forecast and the marketing and network expansion programs.

Figure 13.9 details actual and forecast weather adjusted average residential consumption from 2005 to 2017.

Figure 13.9: Residential Average Consumption GJ pa - Actual Weather Adjusted, 2005 to 2017



The following key factors are driving the continual decline in average residential consumption:

(1) historic underlying trend decline in average consumption;

(2) change to 6 star building standard;

(3) introduction of carbon price;

(4) wholesale gas price increases; and

(5) network price increases.

13.5.2.1 Base Forecast

The base forecast is derived from the continuation of the trend decline in average residential consumption, the drivers for which have been explained in section 13.3.1 above, multiplied by the increase in customer numbers. The resultant base forecast extrapolating the underlying trend in gas usage is shown in the table below:

Table 13.3: Residential Base Forecast

Base Forecast	2013	2014	2015	2016	2017
Residential Tariff V (TJ)	27,030	27,351	27,657	27,959	28,253

13.5.2.2 Change to 6 star building standard

From May 2011, all new homes and major renovations must meet the 6 star building standards. Unlike other government policy measures, this policy is not present in the historic data as it was introduced in May 2011 and as such, an adjustment to the base forecast is required. The Australian Building Codes Board (ABCB) published a Final Regulation Impact Statement (RIS) in December 2009, which report identified the impact of shifting to a 6 star standard in Victoria.

The RIS identified a reduction[174] in heating gas consumption of:

- 6.5GJ per customer per annum for a house;
- 2.7GJ per customer per annum for a townhouse; and
- 2.6GJ per customer per annum for a flat

The above volumes were applied to the projected customer number growth to determine the total adjustment required to the volume forecast, which amount is detailed in table 13.4.

Table 13.4: Six Star Building Standard Impact on Residential Base Forecast

6 Star Impact	2013	2014	2015	2016	2017
Residential Tariff V (TJ)	- 142	- 211	- 279	- 349	- 418

13.5.2.3 Introduction of a Carbon Price

Envestra's customers will face a carbon price from 1 July 2012. Commonwealth Treasury modeling indicates the opening carbon price of $23/t$CO_2$e will lead to an increase to the residential gas price of 9%[175], followed by annual increases of 0.66% thereafter. Core Energy has applied this price increase in its demand forecast modeling. The impact of the carbon price is shown in the table 13.5.

Table 13.5: Carbon Price Impact on Residential Base Forecast

Carbon Price	2013	2014	2015	2016	2017
Residential Tariff V (TJ)	-330	- 561	- 734	- 867	- 932

13.5.2.3 Wholesale Gas Price

Increases to the wholesale gas price are expected over the period to 2017, largely arising from the development of LNG export facilities in Queensland. Within the current decade, the wholesale gas price will increase as east coast residential use of gas is for the first time exposed to world competition.

174 ABCB Final Regulation Impact Statement for Decision – Proposal to Revise the Energy Efficiency Requirements of the Building Code of Australia for Residential Buildings, December 2009, table 6.2 page 80

175 Commonwealth Treasury Strong Growth, Low Pollution – Modelling a Carbon price; July 2011 Table 5.19 page 137

Core Energy have utilised the Commonwealth Treasury expectation of wholesale gas prices[176], which forecast lies within a range of wholesale gas price expectations of other forecasters (refer appendix 6 of Core Energy's report). The expected real retail gas price increase arising from the wholesale gas price projection is 6% from 2013 to 2017. The impact of the wholesale gas price on residential demand is detailed in table 13.6.

Table 13.6: Wholesale Gas Price Impact on Residential Base Forecast

Wholesale Gas Price	2013	2014	2015	2016	2017
Residential Tariff V (TJ)	- 17	- 63	- 140	- 253	-386

13.5.2.4 Network Development

Network Development increases gas demand by either:

- enabling the connection of previously unconnected homes to the gas network; or
- by promoting a wider application of gas use in the home.

In order to arrest the trend decline in gas usage discussed in section 13.3.1, Envestra has proposed a network development program that continues to offer consumers an incentive to connect to and increase usage of gas (see section 6.5 of the Access Arrangement Information for a further discussion of network development).

The incremental impacts on gas demand of the proposed network development programs form a separate component of Envestra's overall gas demand forecast.

Table 13.7: Network Development Impact on Residential Base Forecast

Network Development	2013	2014	2015	2016	2017
Residential Tariff V (TJ)	+ 8	+ 17	+ 27	+ 38	+ 49

13.5.2.5 New Towns

Envestra has submitted to Regional Development Victoria (RDV) proposals for the network to be expanded to several towns, which towns were listed by the Victorian government as part of its Energy for the Regions program. The towns are Lakes Entrance, Orbost, Koo Wee Rup and Wy Yung.

Envestra expects the expansion of the network to these towns to occur in 2016. The associated demand adjustments therefore only occur in 2016 and 2017 and is detailed in table 13.8.

Table 13.8: New Towns Impact on Residential Base Forecast

New Towns	2013	2014	2015	2016	2017
Residential Tariff V (TJ)	0	0	0	+ 8	+ 27

[176] Commonwealth Treasury Strong Growth, Low Pollution – Modelling a Carbon price; July 2011 Chart B.6

13.5.2.6 Envestra Network Price Increase

Envestra's network price increases will also affect customer demand due to the inverse relationship between price and demand. Core Energy have utilized the same process as that applied for Envestra's South Australian and Queensland networks; whereby an intermediate demand forecast is created and applied to the PTRM to determine the X factors. These X factors are then fed back into Core Energy's model to arrive at the final demand forecast. The impact of the network price increase is detailed in table 13.9.

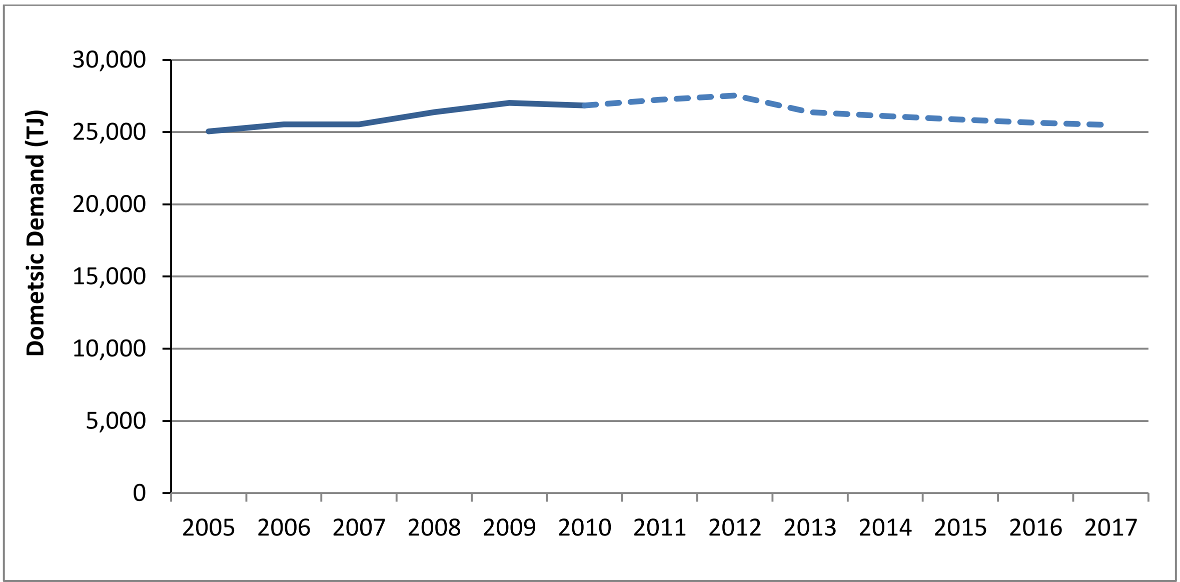
Table 13.9: Network Price Increase Impact on Residential Base Forecast

Network Price Increase	2013	2014	2015	2016	2017
Residential Tariff V (TJ)	- 173	- 424	- 659	- 884	- 1,091

13.5.2.7 Final Residential Forecast

Envestra's final residential demand forecast is a combination of Core Energy's customer number and average consumption forecasts along with the addition of incremental demand from the proposed network development program, network expansions to new towns and the reallocation of customers between the residential and non-residential segments. Figure 13.10 below shows the final demand forecast.

Figure 13.10: Residential Volume TJ pa - Actual Weather Adjusted



Total volume is forecast to decline by 0.7% per annum over the 2013 to 2017 Access Arrangement period. Envestra considers this to be a conservative forecast given the significant and increasing trend decline in average consumption and the current focus of government and consumers to reduce energy usage.

Table 13.10: Residential Demand Forecast, 2013 to 2017

Residential Tariff V (TJ)	2013	2014	2015	2016	2017
Base Forecast	27,030	27,351	27,657	27,959	28,253
less 6 Star	142	211	279	349	418
less Carbon Price	330	561	734	867	932
less Wholesale Gas Price	17	62	140	253	386
plus Network Development	8	17	27	38	49
plus New Towns	0	0	0	8	27
Intermediate Forecast	26,549	26,534	26,531	26,536	26,593
less Network Price	173	424	659	884	1,091
Final Forecast	**26,375**	**26,110**	**25,872**	**25,652**	**25,502**

13.6 Non-Residential Tariff V Forecasts

As per the residential forecast, the key drivers of the non-residential sales forecasts are:

(1) customer numbers; and

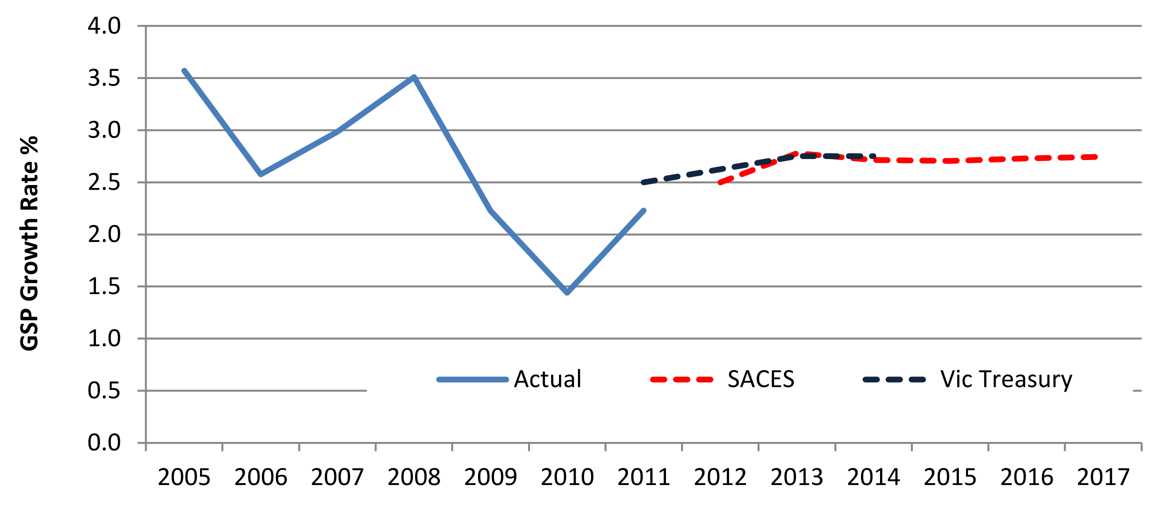
(2) average consumption.

Core Energy's forecasts for non-residential Tariff V volume are derived from a projection of customer numbers and average demand. Historic non-residential volumes were corrected for weather in a manner consistent with residential volume, albeit at a lower sensitivity.

A critical determinant of both the customer number and average demand forecasts is the Gross State Product (GSP). Core Energy procured Victorian GSP forecasts from the South Australian Centre for Economic Studies (SACES), a joint research venture of the Adelaide and Flinders Universities. SACES was established in 1982 and since that time has completed over one thousand research assignments related to applied economics for commonwealth and state government agencies, the private sector and various other bodies.

SACES forecast growth in GSP of 2.7% is the same as the Victorian Treasury forecast of 2.7% (see figure 13.11). Both forecasts are marginally below the actual growth experienced over the past decade of approximately 2.8%.

Figure 13.11: Victorian GSP – Victorian Treasury and SACES



Other than the impact on the retail gas price of the introduction of a price on carbon from 1 July 2012, no other specific policy adjustments have been made. This is a conservative position as the Clean Energy Legislation, of which the carbon tax is a part, did allocate funds directed at improving energy efficiency within the commercial and industrial sectors of the economy.

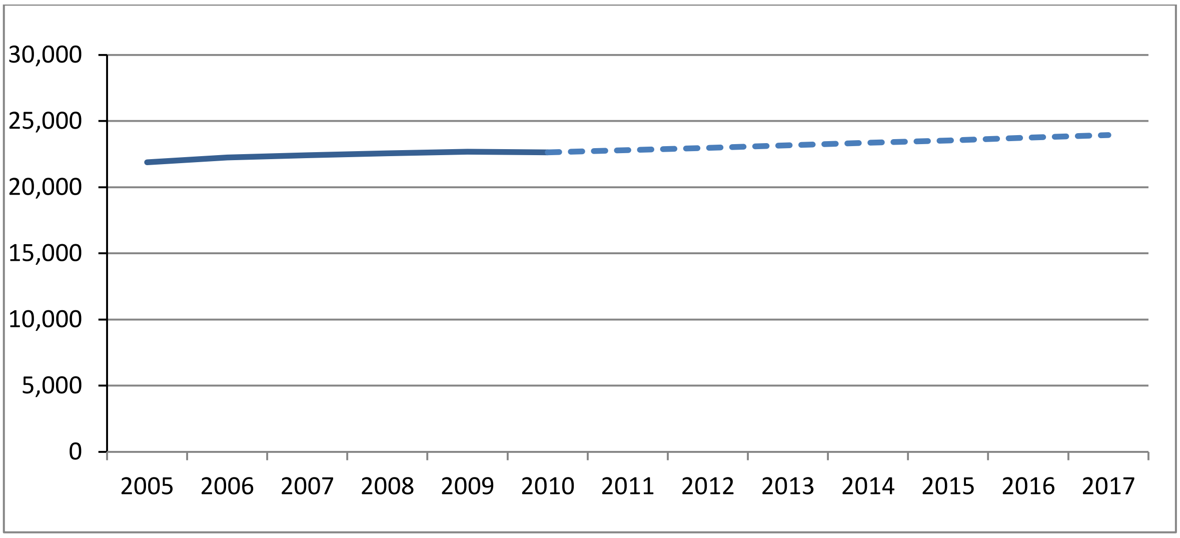
Envestra's final forecast for this segment is a combination of Core Energy's forecast and the expected gains from expanding the network into Lakes Entrance, Orbost, Koo Wee Rup and Wy Yung.

13.6.1 Customer Numbers

Envestra's non-residential customer numbers are projected to grow at 0.8% per annum to 2017, which is marginally above the 0.7% pa growth experienced by Envestra since 2005. The forecast is a combination of Core Energy's customer number forecast (derived from the SACES GSP forecast and an underlying historic trend) and the incremental impacts of Envestra's proposed network expansion programs[177].

[177] Business Case V100

Figure 13.12 Non - Residential Customer Number Forecast



13.6.2 Average Consumption

Envestra's non-residential average consumption is projected to decline by 2.8% per annum over the 2013 to 2017 Access Arrangement period. The forecast decline is made up of the historic trend decline offset by the growth attributable to GSP. The biggest contributors to the forecast decline in average non-residential demand is the retail gas price impact of the:

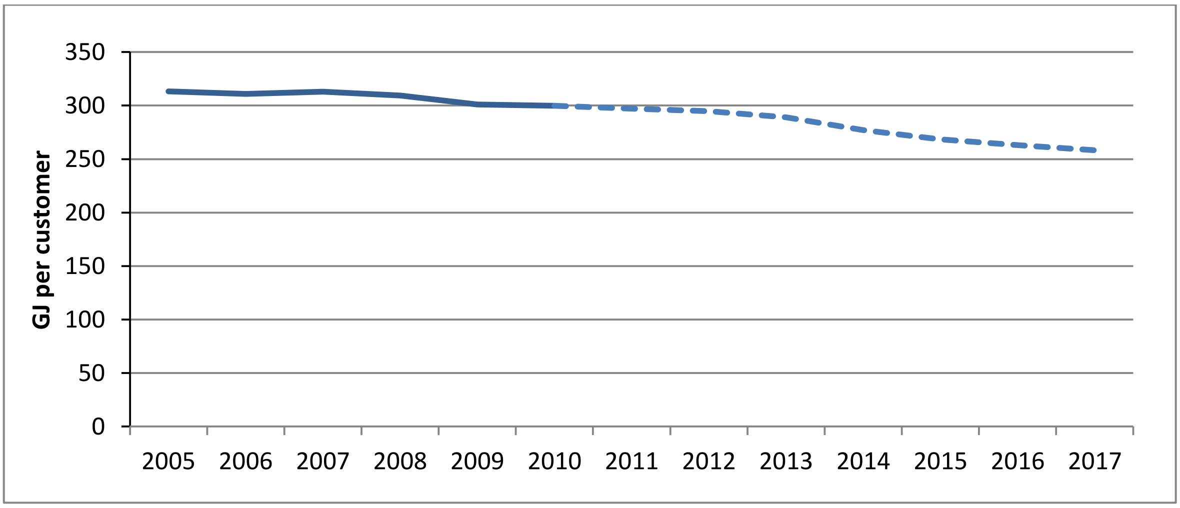
(1) introduction of carbon price;

(2) wholesale gas price increase; and

(3) network price increase.

Figure 13.13 details actual and forecast weather adjusted average non-residential consumption from 2005 to 2017. The approach to adjusting historic consumption for weather is consistent with that used for residential customers and explained in section 13.4.2.

Figure 13.13: Non-Residential Average Consumption GJ pa - Actual Weather Adjusted



13.6.2.1 Base Forecast

The base forecast is derived from the continuation of the underlying decline in average non-residential consumption and the application of the GSP growth forecast (see table 13.11).

Table 13.11: Non-Residential Base Forecast

Base Forecast	2013	2014	2015	2016	2017
Non Residential Tariff V (TJ)	6,923	6,936	6,948	6,964	6,981

13.6.2.2 Introduction of a Carbon Price

As with Envestra's residential customers, non-residential customers will also face a carbon price from 1 July 2012. Utilising Commonwealth Treasury modeling, Core Energy have estimated the impact of the opening carbon price of $23/tCO2e will be an increase to the non-residential retail gas price of 12%[178], followed by annual increases of 0.9% thereafter. The impact of the carbon price is expected to be larger for non-residential consumers when compared against residential consumers as the wholesale gas component of a non-residential consumer is larger than for a residential consumer. Core Energy has applied this price increase in its demand forecast modeling (see table 13.12).

Table 13.12: Carbon Price Impact on Non-Residential Base Forecast

Carbon Price	2013	2014	2015	2016	2017
Non Residential Tariff V (TJ)	- 53	- 187	- 273	- 316	- 340

13.6.2.3 Wholesale Gas Price

As explained earlier, increases to the wholesale gas price are expected over the period to 2017, largely arising from the development of LNG export facilities in Queensland. As with the forecast of residential demand, Core Energy have utilised the Commonwealth Treasury expectation of wholesale gas prices,[179] which delivers an expected real retail gas price increase of 8% from 2013 to 2017 (refer chapter 5 of attachment 13.1). The impact of the wholesale gas is detailed in table 13.13.

Table 13.13: Wholesale Gas Price Impact on Non-Residential Base Forecast

Wholesale Gas Price	2013	2014	2015	2016	2017
Non Residential Tariff V (TJ)	- 3	- 15	- 39	- 77	- 124

13.6.2.4 New Towns

Envestra expects to gain non-residential volumes as the network expands as part of the Energy for the Regions program. The associated demand adjustments occurs for only 2016 and 2017 and is detailed in table 13.14.

178 Refer attachment 13.1, page 44
179 Commonwealth Treasury Strong Growth, Low Pollution – Modelling a Carbon price; July 2011 Chart B.6

Table 13.14: New Towns Impact on Non-Residential Base Forecast

New Towns	2013	2014	2015	2016	2017
Non Residential Tariff V (TJ)	0	0	0	+ 20	+ 30

13.6.2.5 Envestra Network Price Increase

Core Energy have also included the impact of the network price increase on forecast non-residential demand. Core Energy applied the same methodology as it applied for residential demand. The impact of the network price increase is detailed in table 13.15.

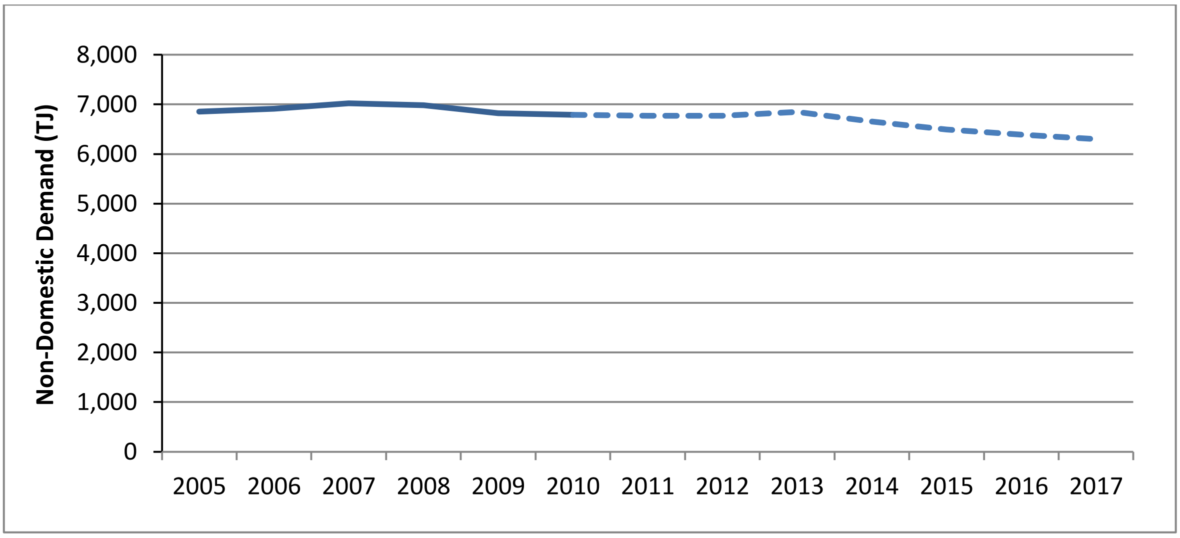
Table 13.15: Network Price Impact on Non-Residential Base Forecast

Network Price Increase	2013	2014	2015	2016	2017
Residential Tariff V (TJ)	- 18	- 76	- 143	- 197	- 242

13.6.2.6 Final Non-Residential Forecast

Envestra's final non-residential demand forecast is a combination of Core Energy's customer number and average consumption forecasts along with the addition of incremental demand from the proposed network expansions to new towns. Figure 13.14 below shows the final demand forecast.

Figure 13.14: Non-Residential Volume TJ pa - Actual weather adjusted



Total volume is forecast to decline by 2.0% per annum over the 2013 to 2017 Access Arrangement period. Envestra considers this to be a conservative forecast given the significant and increasing trend decline in average consumption over an extended duration. As in past periods, there remains a risk that Envestra will again be unable to achieve this modest fall in volumes over the 2013 to 2017 Access Arrangement period, particularly in the light of the current policy environment.

Table 13.16: Non-Residential Demand Forecast, 2013 to 2017

Residential Tariff V (TJ)	2013	2014	2015	2016	2017
Base Forecast	6,923	6,936	6,948	6,964	6,981
less Carbon Price	53	187	273	316	340
less Wholesale Gas Price	3	15	39	77	124
plus New Towns	0	0	0	20	30
Intermediate Forecast	6,867	6,734	6,636	6,592	6,547
less Network Price	18	76	143	197	242
Final Forecast	**6,849**	**6,657**	**6,493**	**6,395**	**6,305**

13.7 Demand Tariff D Customer Forecast

Tariff D Demand customers comprise Envestra's largest network users and use a third of the total gas delivered by Envestra in Victoria. Forecasts of gas (sales) volumes and maximum hourly quantity (MHQ) for Demand customers have been developed by Core Energy.

Core Energy's approach to forecasting Tariff D is the same as that used for forecasting non-residential Tariff V. Tariff D however will not benefit from the proposed expansion of the network to new towns, resulting in only decrements to the base forecast arising from changes to the retail gas price (ie carbon tax, wholesale gas price and network price increases).

13.7.1 Customer Numbers

Envestra's Tariff D customer numbers are projected to grow by 9 customers to 2017, closing at 290 customers, which is the same growth as that experienced by Envestra since 2005.

13.7.2 Average Consumption

Envestra's Tariff D average consumption is projected to decline by 3.9% per annum over the 2013 to 2017 Access Arrangement period. The forecast decline is made up of the historic trend decline offset by the growth attributable to GSP. The biggest contributors to the forecast decline in average non-residential demand is the retail gas price impact of the:

(1) introduction of carbon price;

(2) wholesale gas price increase; and

(3) network price increase.

13.7.2.1 Base Forecast

The base forecast is derived from the continuation of the underlying decline in average Tariff D consumption and the application of the GSP growth forecast (see table 13.17).

Table 13.17: Tariff D Base Forecast

Base Forecast	2013	2014	2015	2016	2017
Tariff D (TJ)	21,599	21,285	20,973	20,672	20,378

13.7.2.2 Introduction of a Carbon Price

As with Envestra's residential and non-residential customers, Tariff D customers will also face a carbon price from 1 July 2012. Utilising Commonwealth Treasury modeling, Core Energy has estimated the impact of the opening carbon price of \$23/tCO2e will be an increase to the Tariff D retail gas price of 18%[180], followed by annual increases of 1.3% thereafter.

The impact of the carbon price is expected to be larger for Tariff D consumers when compared against all other customers as the wholesale gas component of a Tariff D customer's total gas invoice is much larger than for another customer. Core Energy has applied this price increase in its demand forecast modeling. The impact of the carbon price is shown in the table 13.18 below:

Table 13.18: Carbon Price Impact on Tariff D Base Forecast

Carbon Price	2013	2014	2015	2016	2017
Tariff D (TJ)	- 248	- 860	- 1,227	- 1,392	- 1,474

13.7.2.3 Wholesale Gas Price

Increases to the wholesale gas price are expected over the period to 2017, largely arising from the development of LNG export facilities in Queensland. As with the forecast of residential and non-residential demand, Core Energy have utilised the Commonwealth Treasury expectation of wholesale gas prices[181,] which delivers an expected real retail gas price increase of 12% from 2013 to 2017 (refer chapter 4 of attachment 13.1). The impact of the wholesale gas is detailed in table 13.19.

Table 13.19: Wholesale Gas Price Impact on Tariff D Base Forecast

Wholesale Gas Price	2013	2014	2015	2016	2017
Tariff D (TJ)	- 13	- 68	- 176	- 335	- 529

13.7.2.4 Envestra Network Price Increase

Core Energy has also included the impact of the network price increase on forecast non-residential demand. Core Energy applied the same methodology as it applied for residential and non-residential demand, however the impact is negligible as the network component of a Tariff D consumer's total gas invoice is very small. The impact of the network price increase is detailed in table 13.20.

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180 Refer Chapter 4 of attachment 13-1

181 Commonwealth Treasury Strong Growth, Low Pollution – Modelling a Carbon price; July 2011 Chart B.6

Table 13.20: Network Price Impact on Tariff D Base Forecast

Network Price Increase	2013	2014	2015	2016	2017
Residential Tariff V (TJ)	- 9	- 39	- 71	- 96	- 116

13.7.2.5 Final Tariff D Forecast

Table 13.21 below shows the final demand forecast.

Table 13.21: Tariff D Demand Forecast, 2013 to 2017

Tariff D (TJ)	2013	2014	2015	2016	2017
Base Forecast	21,599	21,285	20,973	20,672	20,378
less Carbon Price	248	860	1,227	1,392	1,474
less Wholesale Gas Price	13	68	176	335	529
Intermediate Forecast	21,338	20,356	19,569	18,945	18,375
less Network Price	9	39	71	96	116
Final Forecast	**21,330**	**20,317**	**19,498**	**18,848**	**18,259**

The final step required is to convert the GJ demand projection into a Maximum Hourly Quantity (MHQ) projection, which conversion is done by multiplying the final demand forecast by the capacity utilisation factor. Core Energy have applied the average capacity utilization factor of the 2005-2010 period of 38.4%.[182]

Table 13.22: Tariff D GJ MHQ Forecast, 2013 to 2017

Tariff D (GJ MHQ)	2013	2014	2015	2016	2017
Final Forecast	5,716	5,416	5,172	4,979	4,804

13.8 Overall Forecast

Table 13.23 below summarises the total Envestra demand and customer number forecast over the 2013 to 2017 Access Arrangement period.

[182] The final MHQ has been adjusted for the shutdown of Bluescope Steel's Hotstrip Mill, which MHQ is 607GJ. The adjusted MHQ is presented in table 13.24.

Table 13.23: Final Demand and Customer Number Forecasts, 2013 to 2017

Residential Tariff V	2013	2014	2015	2016	2017
Customer Numbers	563,761	576,037	588,197	600,872	613,696
Demand (TJ)	26,374	26,108	25,868	25,646	25,493
Non -Residential Tariff V (TJ)					
Customer Numbers	25,395	25,586	25,776	26,023	26,266
Demand (TJ)	6,849	6,657	6,493	6,395	6,305
Tariff D					
Customer Numbers	281	283	285	288	290
Demand (GJ MHQ)	5,716	5,416	5,172	4,979	4,804

Table 13.24 below details the gross connection forecast to 2017 used in developing the capital expenditure program. The gross connection forecast is derived from the net connection growth forecast plus an allowance for connection losses (ie demolitions). Forecast connection losses are calculated by applying the historic proportion of connection losses to connection gains to the forecast net customer growth, which historic proportions are 15% for residential and 50% for non-residential connections.

The gross connection forecast does not include new connections for the proposed network expansion into new towns as they form separate capital programs within the overall capital expenditure program.

Table 13.24: Gross Connection Forecast, 2013 to 2017

Gross Connections	2013	2014	2015	2016	2017
New Homes	11,233	11,090	10,986	11,074	11,066
Existing Homes	2,650	2,615	2,589	2,609	2,605
Multi User	736	726	719	725	724
C&I	395	381	380	391	398
Total	**15,014**	**14,811**	**14,674**	**14,798**	**14,793**

13.9 Use of Demand Forecasts

13.9.1 Development of Capital Expenditure and Operating Expenditure Forecasts

The growth capital expenditure forecast for Tariff V customers is directly related to the gross connection forecasts by customer class. The capital expenditure is calculated by applying unit rates of construction relating to mains, inlets and meters by customer class to the gross connection forecast.

Operating expenditure forecasts are partially driven by the incremental customer number forecasts, ie incremental costs arising from every new connection to the network.

13.9.2 Tariff Billable Quantities

The forecasts presented in this chapter must be converted into the associated charging parameters in order to calculate forecast tariff revenue over the regulatory period (see chapters 14 and 15 for further discussion on tariffs, tariff classes, charging parameters and tariff structures). Supply charge days were determined by taking the customer numbers for each year multiplied by 365. The total demand forecasts are apportioned to each zone and tariff component (ie volume or MHQ block of consumption) in accordance with customers' historic consumption profiles.

14. Reference Tariffs

14.1 Introduction

Chapter 12 sets out Envestra's total revenue requirements for each year of the 2013 to 2017 Access Arrangement period. Envestra recovers this revenue by charging Haulage Reference Tariffs and Ancillary Reference Tariffs to customers connected to the network. This chapter details the proposed tariffs to apply in the 2013 to 2017 Access Arrangement period, including explaining how those tariffs comply with the National Gas Rules (NGR).

14.2 Requirements of the National Gas Rules

Rule 93 of the NGR imposes the following requirements on Envestra regarding the allocation of revenue and costs to reference services:

"93(1) Total Revenue is to be allocated between reference and other services in the ratio in which costs are allocated between reference and other services.

93(2) Costs are to be allocated between reference and other services as follows:

(a) costs directly attributable to reference services are to be allocated to those services; and

(b) costs directly attributable to pipeline services that are not reference services are to be allocated to those services; and

(c) other costs are to be allocated between reference and other services on a basis (which must be consistent with the revenue and pricing principles) determined or approved by the AER."

Rule 94 of the NGR imposes the following requirements on Envestra regarding the development of reference tariffs:

"94(1) For the purpose of determining reference tariffs, customers for reference services provided by means of a distribution pipeline must be divided into tariff classes.

94(2) A tariff class must be constituted with regard to:

(a) the need to group customers for reference services together on an economically efficient basis; and

(b) the need to avoid unnecessary transaction costs.

94(3) For each tariff class, the revenue expected to be recovered should lie on or between:

(a) an upper bound representing the stand alone cost of providing the reference service to customers who belong to that class; and

(b) a lower bound representing the avoidable cost of not providing the reference service to those customers.

94(4) A tariff, and if it consists of 2 or more charging parameters, each charging parameter for a tariff class:

(a) must take into account the long run marginal cost for the reference service or, in the case of a charging parameter, for the element of the service to which the charging parameter relates;

(b) must be determined having regard to:

(i) transaction costs associated with the tariff or each charging parameter; and

(ii) whether customers belonging to the relevant tariff class are able or likely to respond to price signals.

94(5) If, however, as a result of the operation of sub-rule (4), the service provider may not recover the expected revenue, the tariffs must be adjusted to ensure recovery of expected revenue with minimum distortion to efficient patterns of consumption.

94(6) The AER's discretion under this rule is limited."

14.3 Allocation of Total Revenue and Costs

Envestra provides reference and non-reference services (also known as other services) to its customers, which services are explained in chapter 4 of this Access Arrangement Information (AAI).

The costs set out in this AAI, particularly those set out in chapters 6 and 7, relate to providing reference services only (and are based on those costs set out in our regulatory accounts). The costs incurred in providing non-reference services are directly incurred and recovered from the particular customer requesting the service, and as such, are not included in this AAI.

The costs of providing Ancillary Reference Services are subtracted from the total revenue requirement and recovered through separate tariffs (which tariff reflects the cost of providing the relevant service). Envestra has developed a cost allocation model (CAM) to allocate revenue to the following two Haulage Reference Services to be provided by Envestra over the 2013 to 2017 Access Arrangement period:

(1) *Tariff D Haulage Service* – which provides for the firm haulage of gas to a Delivery Supply Point (DSP) with a consumption that exceeds 10 terrajoules per year or 10 gigajoules per hour; and

(2) *Tariff V Haulage Service* – this service applies to all other DSPs.

The CAM, which is provided as attachment 14.1 to this AAI, sets out the basis of the allocation of costs between these two reference services. The CAM allocates the building block revenue components set out in chapter 12 to each tariff class on the basis of a number of difference cost allocators, which include a combination of asset values, customer numbers and consumption. The allocators selected reflect the best estimate of the cost to Envestra of servicing each customer class.

There has been no significant change in cost allocation between Tariff D and Tariff V customers proposed by Envestra for the 2013 to 2017 Access Arrangement period. This is not surprising given the detailed CAM developed by the Victorian Government to guide the development of the first set of reference tariffs in 1998.

14.4 Tariff Classes and Tariffs

Rule 94(1) requires customers for the Demand and Volume Haulage Reference Services to be divided into tariff classes.

Customers are assigned to a particular tariff class within a Haulage Reference Service on the basis of their geographic location (see table 14.1). Envestra is proposing to further split Tariff V customers into a "residential" or "non-residential" tariff, reflecting the different drivers of demand and different usage profiles of each customer group. The separation will enable more targeted (and hence efficient) pricing structures to be developed, particularly in respect of residential customers.

Table 14.1: Victorian Tariff Classes

Haulage Reference Service	Tariff Class	Tariff	Geographical Zone
Volume	Tariff V – Central	Residential	Central
Volume	Tariff V – Central	Non-Residential	Central
Volume	Tariff V – North	Residential	North
Volume	Tariff V – North	Non-Residential	North
Volume	Tariff V – Murray Valley	Residential	Murray Valley
Volume	Tariff V – Murray Valley	Non-Residential	Murray Valley
Volume	Tariff V – Bairnsdale	Residential	Bairnsdale
Volume	Tariff V – Bairnsdale	Non-Residential	Bairnsdale
Demand	Tariff D – North & Central	Tariff D	North & Central
Demand	Tariff D – Murray Valley	Tariff D	Murray Valley
Demand	Tariff D – Bairnsdale	Tariff D	Bairnsdale

14.4.1 Volume Tariff Class

As shown in table 14.1, each volume tariff class will comprise a residential and non-residential tariff for each of the different zones of Envestra's network (no new zones have been proposed by Envestra). Both residential and non-residential tariffs will comprise the following charging parameters:

- supply charge (in dollars per day); and
- banded volume charges (in dollars per GJ per day).

These are discussed in turn below.

14.4.1.1 Supply Charge

The supply charge is a fixed daily charge that applies to all Delivery Points. The same supply charge is to apply to residential and non-residential Delivery Points, and is designed to signal to customers:

- the fixed cost nature of natural gas distribution; and

- the cost to connection customers to the distribution network, having regard to the size, location and type of network user.

14.4.1.2 Banded Volume Charges

Both residential and non-residential tariffs consist of a number of volumetric (or consumption) based charging parameters (in dollars per GJ per day). The proposed residential tariff will comprise the following three volumetric:

- a charge for the first 0.0274GJ of Gas Delivered ($/GJ) per day – equating to 10GJ per annum;
- a charge for the next 0.0219GJ of Gas Delivered ($/GJ) per day – equating to 8GJ per annum; and
- a charge for Additional Gas Delivered ($/GJ).

The first step of consumption broadly captures a customer using a gas cooker and solar hot water system, the second step captures a customer with a non-solar gas hot water system while the final step captures customers utilising gas for space heating. Envestra has not proposed to continue to differentiate between peak (June to September) and off peak (October to May) periods due to the lack of ability to influence customer behaviour on a seasonal basis (refer section 14.9 below).

Non-residential tariffs will maintain the following four volumetric consumption bands, however the steps are different to that applying over the 2008 to 2012 Access Arrangement period:

- a charge for the first 0.05GJ of Gas Delivered ($/GJ) per day – equating to 18GJ per annum;
- a charge for the next 0.50GJ of Gas Delivered ($/GJ) – equating to 183GJ per annum;
- a charge for the next 0.82GJ of Gas Delivered ($/GJ) – equating to 299GJ per annum; and
- a charge for Additional Gas Delivered ($/GJ).

Non-residential will also no longer differentiate between peak and off peak periods.

Residential and non-residential tariffs are structured as "declining block tariffs". The declining block structures are intended to reflect the relatively low marginal cost associated with the ongoing supply of natural gas to a Delivery Point and are also designed to encourage greater network utilisation, thereby assisting Envestra to arrest the long term decline in average consumption.

The locational aspect of the volume tariffs reflects the cost of service within each zone and provides some incentive to customers, particularly the non-residential customers, to connect to those parts of the network where the cost of gas supply is relatively lower, which generally occurs in areas of high customer density.

14.4.2 Demand Tariff Classes – Tariff D

The structure of the demand tariff classes consists of a number of banded Maximum Hourly Quantity (MHQ) charging parameters (in dollars per GJ of MHQ per hour). Consistent with the volume tariffs, Tariff D is also structures as declining block tariffs, whereby the charge becomes smaller as MHQ increases (again to promote greater network utilisation).

The MHQ charges are capacity based charges reflecting the key cost driver in supplying demand customers[183]. The structure provides economic signals to demand customers to have a smooth consumption profile as opposed to a "peaky" profile. A flat profile results in improved network utilisation and therefore lower costs in providing network services (as the size of the network required to supply the customer will be lower). Like volume customers, the locational price encourages demand customers to locate to those parts of the network that will impose the least costs to Envestra (and hence customers).

Three MHQ bands that are to apply in each zone are as follows:

- MHQ of 10GJ or less;
- next 40GJ of MHQ; and
- additional GJ of MHQ.

No changes are proposed to the structure of Tariff D.

14.4.3 Ancillary Reference Services

Envestra proposes to maintain the structure and rate (in real terms) of its Reference Tariffs for Ancillary Reference Services over the 2013 to 2017 Access Arrangement period. The Ancillary Reference Services are set out in table 14.2 and explained in more detail in chapter 4.

Table 14.2: Price Forecast for Ancillary Reference Services, 2013 to 2017

	2013 - 2017
Meter and Gas Installation Test	$190.00
Disconnection	$62.00
Reconnections	$73.00
Meter Removal	$90.00
Meter Reinstallation	$90.00
Special Meter Reading - Metro	$8.10
Special Meter Reading – Non Metro	$10.80

14.5 Grouping of Reference Tariffs on an Economically Efficient Basis

Rule 94(2)(a) requires that a tariff class must be constituted with regard to the need to group network users for reference services together on an economically efficient basis.

[183] Customers assigned to a Tariff D charge for a period will also incur the Non-Reference Service local capacity charge (LLC). The LCC recovers the incremental capital costs incurred by Envestra in order to connect the individual demand customer (eg connection assets and specific mains extensions).

Envestra has developed its tariff classes in recognition of the need to group together network users on an economically efficient basis. The tariff classes have been developed to ensure those customers with similar characteristics (and hence costs) are allocated to the same tariff class. Specifically, the tariff classes are based on the:

- nature of the Haulage Reference Service provided to a Delivery Point (i.e. Volume or Demand); and
- the location of the customer on the distribution network.

This grouping of customers is consistent with accepted good industry practice.

14.6 Transaction Costs

Rule (94)(2)(b) requires each tariff class to be constituted with regard to the need to avoid unnecessary transaction costs. Rule 94(4)(b)(i) requires that a tariff, and if it consists of two or more charging parameters, each charging parameter for a tariff class, must be determined having regard to the transaction costs associated with the tariff or each charging parameter.

Envestra considers its proposed reference tariff structures (including Ancillary Reference Services) and associated charging parameters, which are consistent with industry standards, effectively balance Envestra's objectives of minimising transaction costs and providing appropriate price signals to network users.

With regard to tariff classes, Envestra is proposing separate residential and non-residential tariffs apply to each tariff class for the 20013 to 2017 Access Arrangement period as opposed to the current single tariff. The transaction costs incurred as a result of the separation of residential and non-residential tariffs are likely to be low, particularly given retailers already offer residential and non-residential volume tariffs.

With regard to charging parameters, Envestra has consolidated the number of charging parameters by removing the seasonal price differential for residential and non-residential tariffs. The residential structure will comprise only four components (supply charge and three usage components) compared to the current nine (supply charge and eight usage components). The non-residential structure will compose only five components (supply charge and four usage components) compared to the current nine (supply charge and eight usage components).

The likely transaction costs associated with Envestra's tariffs are likely to be consistent with that across the gas industry given its tariffs structures are consistent with industry practice. Envestra also considers transaction costs will be no higher than is currently the case despite the introduction of the residential tariffs, particularly given the reduction in charging parameters driven by the removal of peak/off-peak pricing signals (indeed, it is expected that transaction costs will be lower).

14.7 Avoidable and Stand-Alone Costs

Rule 94(3) requires that for each tariff class, the revenue expected to be recovered should lie on or between:

(a) an upper bound representing the stand alone cost of providing the reference service to customers who belong to that class; and

(b) a lower bound representing the avoidable cost of not providing the reference service to those customers.

Consistent with Envestra's approach in South Australia and Queensland, Envestra has defined the stand-alone costs for each tariff class as the costs of providing a distribution network to supply only that tariff class.[184] These costs represent the upper bound of providing reference services to each tariff class, because the costs are calculated based on the assumption that no other network users use the network infrastructure, thereby ignoring the economies of scale that result from the other tariff classes that are also currently using the shared infrastructure.

Envestra has defined avoidable cost for each tariff class to be the cost that can be avoided by not providing reference services to that tariff class. Put another way, this represents the costs (i.e. the return on capital, depreciation and operating expenditure costs) associated with dedicated connection assets such as meters, inlets and services.

Envestra's CAM calculates the standalone and avoidable cost for each tariff class and demonstrates that the revenue expected to be recovered from each tariff class lies on or between the stand alone and avoidable cost of providing reference services. The methodology applied in the CAM is the same as that used by Envestra for its South Australian and Queensland networks, which approach was approved by the AER as satisfying rule 94(3).[185],[186]

The stand-alone cost for all tariff classes was determined to be the cost associated with the major transmission and high pressure distribution mains forming the core of the network plus the regulator stations. These assets comprise the large diameter, high pressure pipe used in the networks to service customers. The costs of these assets were based on the similar costs determined in the original CAM undertaken to set tariffs in 1998.

The derivation of stand-alone costs for volume customers includes the dedicated connection assets used to supply residential and non-residential customers. These dedicated connection assets do not form part of the stand-alone cost as they are recovered separately through the individual Local Capacity Charge (LLC), which is a Non-Reference Service and therefore does not form part of the Demand Haulage Reference Service.

This approach results in the same stand-alone cost for all demand customers, while that calculated for volume customers differs depending on the allocation of connection assets to the particular customer groups. The stand-alone cost for Ancillary Reference Services is the same as the revenue recovered, which reflects the fact that the cost of providing the service equals the revenue recovered from customers.

The avoidable cost is defined as the cost that can be avoided by not providing reference services to a particular tariff class. The avoidable costs for Tariff D customers is zero as dedicated connection assets are recovered separately through the individual LLC. The avoidable cost for Tariff V customers is defined as the costs (i.e. return on capital, depreciation and operating expenditure) associated with dedicated connection assets, such as services and meters.

[184] Submission to the Australian Energy Regulator – South Australian Access Arrangement Proposal 2011/12 to 2015/16, Envestra, 1 October 2010, pg 212

[185] Envestra Access Arrangement Proposal SA - Draft Decision, AER, February 2011 pg 199.

[186] Envestra Access Arrangement Proposal QLD - Draft Decision, AER, February 2011 pg 180.

Table 14.3 shows the outputs of the CAM regarding stand-alone and avoidable costs. The table demonstrates that the 2013 weighted average revenue for each tariff class lies above the lower bound avoidable cost and below the upper bound stand alone cost. Envestra's reference tariffs therefore comply with Rule 94(3) of the NGR in all cases.

Table 14.3: Avoidable, Expected and Stand Alone Costs (excluding GST) $2013

Tariff Class	Avoidable Costs ($M)	Weighted Average Revenue ($M)	Stand Alone Costs ($M)	Complies
Tariff V: Central	14.20	165.65	185.33	Yes
Tariff V: North	1.94	19.67	53.60	Yes
Tariff V: Murray Valley (Vic)	0.23	1.76	34.54	Yes
Tariff V: Bairnsdale	0.08	1.15	33.41	Yes
Tariff D: Central/North	0.00	3.97	16.42	Yes
Tariff D: Murray Valley (Vic)	0.00	0.11	16.42	Yes
Tariff D: Bairnsdale	0.00	0.04	16.42	Yes
Meter and Gas Installation Test	0.00	0.01	0.01	Yes
Disconnection Test	0.00	0.45	0.45	Yes
Reconnection	0.00	0.50	0.50	Yes
Meter Removal	0.00	0.17	0.17	Yes
Meter Reinstallation	0.00	0.01	0.01	Yes
Special Meter Reads	0.00	1.25	1.25	Yes

14.8 Long Run Marginal Costs

Rule 94(4)(a) requires Envestra to take into account the long run marginal cost (LRMC) for each reference service or for each element of the service to which the charging parameter relates.

LRMC is not defined in the NGR. Envestra interprets LRMC to be the costs of providing network capacity increments in the long term, which definition was also applied to Envestra's South Australian and Queensland networks. Envestra notes the consistency with Integral Energy's interpretations in their Pricing Proposals, which first defined short run marginal cost as:[187]

> *"The cost to society of a network user using existing capacity in the network at any point in time. This is generally very low unless the system is capacity constrained, and reflects the fact that the great majority of the costs of an electricity network provider are fixed in the short run and do not vary with the usage of the network".*

[187] Direct Control Services Annual Pricing Proposal 2010/11, Integral Energy, 30 April 2010, p78.

Integral Energy then defined LRMC as "a situation in which the investment in plant and equipment is variable", and further noted that LRMC will "relate broadly to the annualised cost of augmenting capacity (in the case of electricity, at a particular voltage, at a particular location, at a particular time), generally, per unit of additional capacity provided (i.e., kW or kVA)."[188]

This definition of LRMC was accepted by the AER as satisfying rule 94(4)(a) in its review of Envestra's South Australian and Queensland networks[189]. Envestra has therefore applied the same definition to its Victorian networks.

14.8.1 Envestra's Approach to Calculating LRMC

Envestra's approach to calculating the LRMC was developed with regard to the methodologies adopted for Envestra's South Australian and Queensland networks, which was also used by several other distributors including Jemena Gas Networks (Jemena) in NSW[190], ActewAGL[191] and ETSA Utilities[192]. In all cases the methodology has been accepted by the AER.

This methodology applies the Average Incremental Cost (AIC) approach, whereby the present value of the incremental investment (both capital and operating expenditure) associated with increasing capacity in the long term is divided by the present value of the change in incremental demand. The AIC approach to calculating the LRMC can be expressed as follows:

$$LRMC = \frac{PV\ (growth\ related\ shared\ network\ capex)\ +\ PV\ (growth\ related\ shared\ network\ opex)}{PV\ (incremental\ demand)}$$

where:

- *growth related shared network capex* is the forecast annual capital expenditure (capex) in shared network assets required to meet additional demand over the nominated forecast period;
- *growth related shared network opex* is the forecast annual operating expenditure (opex) required to operate and maintain the shared network assets required to meet additional demand over the nominated forecast period; and
- *incremental demand* is the change in gas demand (in GJ) for each year over the nominated forecast period.

Using the methodology outlined above, Envestra attempted to calculate the LRMC for its distribution networks in Victoria by tariff class. Envestra considers that calculating the LRMC by tariff class, rather than on a whole-of-network basis, is consistent with NERA Economic Consulting's view[193] that it is inaccurate to refer to a universal marginal cost. Specifically, the LRMC varies on the basis of factors including customer type, location and gas consumption profiles.

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188 ibid
189 Envestra Access Arrangement Proposal SA - Draft Decision, AER, February 2011 pg 199.
190 Jemena Gas Networks (NSW) – Access Arrangement Information – Appendix 15.4 Long Run Marginal Cost Report 26 August 2009.
191 ActewAGL Distribution Access arrangement information for the ACT, Queanbeyan and Palerang gas distribution network, June 2009.
192 ETSA Utilities Pricing Proposal 2010-11, June 2010.
193 NERA Economic Consulting, Distribution Pricing Rule Framework Network Policy Working Group, December 2006, p32.

These factors are reflected into Envestra's tariff classes, and as a result, Envestra has attempted to calculate the LRMC for each of its tariff classes.

14.8.2 Considerations in the Calculation of LRMC

14.8.2.1 Growth Related Expenditure

Consistent with past approaches, only forecast expenditure (both capital and operating expenditure) relating to the forecast growth of the shared network to service additional customer demand is included in Envestra's LRMC calculation. This is because the calculation of the LRMC relies on the key assumptions that expenditure on shared network assets is driven by growth in customer demand.

Forecast expenditure associated with connection assets such as meters and inlets are not included in the LRMC calculation. This is because connection assets are typically dedicated to specific customers and are driven by customer numbers, not demand growth.

14.8.2.2 Forecast period

The length of the forecast period over which the LRMC is calculated should take into consideration the useful life of shared network assets. However, the forecast period is not typically set to equal the useful life of new network assets (which can be as long as 60 years) because capital expenditure, operating expenditure and demand forecasts cannot be produced for such a long period into the future with any degree of accuracy.

Envestra adopted a forecast period of ten years as it considers that a ten year forecast period captures long run costs without drawing on forecasts that are projected too far into the future to be reliable. Furthermore, a ten year forecast period is consistent with that used by Envestra in South Australia and Queensland as well as by ETSA Utilities, which period was in turn was accepted by the AER.

14.8.3 LRMC Calculation Outcomes

Envestra was unable to calculate reasonable values for the LRMC at the tariff class level, by geographical region or even at a whole-of-network level for Victoria. The LRMC values calculated were either too large (relative to the actual tariffs within each tariff class) or negative. Envestra analysed the data and underlying assumptions which led to these outcomes and identified that:

(1) forecast capital expenditure and operating expenditure cannot be produced down to the tariff class level or by geographical location in Victoria. Consequently, Envestra needed to pro-rata the expenditure based on a combination of customer numbers and consumption in order to derive expenditure at the tariff class level;

(2) the forecast growth-related capital expenditure and operating expenditure relates to projects which only affect small segments of the gas distribution network that are experiencing localised growth in customer numbers; and

(3) gas consumption is not growing steadily for any of the tariff classes in Victoria. In fact, demand growth for Victorian volume customers is declining (i.e. negative growth) over the next ten years (see chapter 13).

This means that:

(1) there is insufficient data at the level of granularity required to accurately and meaningfully calculate the LRMC by geographical region and by tariff class; and

(2) the forecast expenditure and demand data suggests that at the tariff class level, expenditure on shared network assets is not driven by growth in customer demand.

As a result, it is not possible for Envestra to obtain reasonable LRMC outcomes using the AIC approach given the data limitations. Further, Envestra is not aware of any other suitable or practical approaches to quantifying the LRMC in light of the issues identified above.

14.8.4 Consideration of LRMC

Despite not being able to quantify the LRMC, Envestra has still had regard for the LRMC when determining its tariffs. Consistent with Envestra's approach in South Australia and Queensland as well as that taken by Ergon Energy's, Envestra has designed its tariff parameters in order to effectively signal LRMC to network users, in particular to signal the impact that network users will have on the cost of providing network services. [194] This is evidenced in Envestra's tariffs by the use of:

(1) Geographic price signals – which signal the cost to the customer of connecting to a particular geographic zone;

(2) Declining block structure – which signal to the customer the declining incremental cost of additional gas consumption (reflecting the low margin cost of services); and

(3) Capacity based charges – which signal to demand customers the impact of peak demand on capital expenditure.

14.8.5 LRMC and Ancillary Reference Services

The provision of Ancillary Reference Services is an operating expense incurred by Envestra. There is no change in the long run cost of providing the services irrespective of the quantity of these services demanded. The tariff applied to customers requiring an Ancillary Reference Service is therefore a flat rate as there is no long run marginal cost to signal to customers.

14.9 Response to Price Signals

Rule (94)(4)(b) of the NGR requires that a tariff, and if it consists of two or more charging parameters, each charging parameter for a tariff class, must be determined having regard to whether network users belonging to the relevant tariff class are able or likely to respond to price signals.

[194] Pricing Proposal to the Australian Energy Regulator - Distribution Services for 1 July 2010 to 30 June 2011, Ergon Energy, 4 June 2010, p53.

Envestra has developed its tariffs and the charging parameters that constitute each tariff in such a manner so that customers are able or likely to respond to price signals. For this reason, Envestra has removed the peak and off peak price differentiation from the residential and non-residential tariffs. Envestra has not discerned an ability of customers to respond to the seasonal signal. For example, customers cannot shift heating load to the off peak period.

The way in which the Tariff D, residential and non-residential Tariff V and Ancillary Reference Services and their associated charging parameters, have been developed is set out below. Envestra's proposed Reference Tariffs for 2013 are set out in Annexure B of the Access Arrangement.

14.9.1 Demand Tariffs

Tariff D has been structured so that customers can respond to pricing signals whilst providing certainty to network users on the amount of their annual charge. Tariff D customers are charged the higher of their agreed or actual MHQ measured from January through to September. A review is conducted in October to identify customers whose actual MHQ for the year has fallen below the agreed MHQ, with the agreed MHQ being reset to the lower actual MHQ at this time.

Consequently, the Tariff D tariff structure incentivises customers to manage their actual gas consumption within the constraints of their agreed MHQ, particularly as customers will automatically receive a lower network charge where their actual MHQ falls below the agreed MHQ. This promotes better capacity utilisation of Envestra's network.

14.9.2 Residential and Non-Residential Tariffs

Residential and non-residential tariffs are structured as declining block tariffs, which provides a strong incentive for customers to increase their usage, either by connecting additional gas appliances or using existing appliances more. Furthermore, the residential threshold that defines the step between the first, second and third tariff bands has been set with regard to the spread of appliances across domestic network users in Victoria. Both these measures promote efficient use of the network and assist Envestra to arrest the long term decline in average consumption.

As noted earlier, the peak and off peak price differential has been removed from the residential and non-residential tariffs given the limited ability for customers to respond to this pricing signal.

14.9.3 Ancillary Reference Services

Ancillary Reference Service tariffs reflect the operating expense to Envestra of providing these services. Each tariff reflects the actual cost to Envestra of providing each service and therefore delivers the appropriate price signal.

14.10 Summary

Envestra recovers its regulated revenue by charging tariffs to customers for Demand Haulage Reference Services, Volume Haulage Reference Services and Ancillary Reference Services. The key change to tariffs is the introduction of residential and non-residential tariffs and the removal of seasonal pricing. All other Reference Tariffs have the same structure as that applying over the 2008 to 2012 Access Arrangement period.

The change in volume tariffs reflects the different drivers of demand and different usage profiles of each customer type. The separation will enable flexibility in price signaling as Envestra responds to the challenges affecting volume customers, particularly the continued decline of average residential consumption. This will also result in tariff structures in Victoria being consistent with the tariffs approved by the AER for our South Australian and Queensland customers.

Envestra's tariff structures are efficient, contain no cross subsidy and have taken into account factors such as transaction costs, LRMC and the ability for consumers to respond to price changes.

15. Tariff Variation Mechanism

15.1 Introduction

Chapter 14 set out the proposed reference tariffs to apply during the 2013 to 2017 Access Arrangement period. This chapter details how these tariffs are to be adjusted over time, including the annual process for the regulatory approval of the tariffs by the Australian Energy Regulator (AER).

15.2 Requirements of the National Gas Rules

Rule 97 of the National Gas Rules (NGR) provides that:

> *"(1) Reference Tariff variation mechanism may provide for variation of a reference tariff:*
>
> > *(a) in accordance with a schedule of fixed tariffs; or*
> >
> > *(b) in accordance with a formula set out in the access arrangement; or*
> >
> > *(c) as a result of a cost pass through for a defined event (such as a cost pass through for a particular tax); or*
> >
> > *(d) by the combined operation of 2 or more of the above".*
>
> *(2) A formula for variation of a reference tariff may (for example) provide for:*
>
> > *(a) variable caps on the revenue to be derived from a particular combination of reference services; or*
> >
> > *(b) tariff basked price control; or*
> >
> > *(c) revenue yield price control; or*
> >
> > *(d) a combination of all or any of the above.*
>
> *(3) In deciding whether a particular reference tariff variation mechanism is appropriate to a particular access arrangement, the AER must have regard to:*
>
> > *(a) the need for efficient tariff structures; and*
> >
> > *(b) the possible administrative effects of the reference tariff variation mechanism on administrative costs of the AER, the service provider, and users or potential users; and*
> >
> > *(c) the regulatory arrangements (if any) applicable to the relevant reference service before the commencement of the proposed reference tariff variation mechanism; and*
> >
> > *(d) the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction); and*
> >
> > *(e) any other relevant factor.*

(4) *A reference tariff variation mechanism must give the AER adequate oversight or powers of approval over variation of the reference tariff.*

(5) *Except as provided by a reference tariff variation mechanism, a reference tariff is not to vary during the course of an access arrangement period."*

15.3 Haulage Reference Services

The following sections detail the various tariff control formulae proposed to be included in the tariff variation mechanism included in the Reference Tariff Policy of the Access Arrangement.

15.3.1 Tariff Variation Mechanism

Consistent with rule 97(1), clause 2.6.4.1(a) of the Regulatory Information Notice (RIN) issued by the AER requires Envestra to"

> *"Outline the proposed reference tariff variation mechanism and the basis for any parameters used in the mechanism".*

Envestra proposes to maintain the current annual tariff variation mechanism in the form of a weighted average price cap (WAPC) formula for the 2013 to 2017 Access Arrangement period. The WAPC mechanism is allowed under rule 97(2) (b) as it is a form of a tariff basket price control.

A WAPC constrains the overall movement in reference tariffs (as opposed to individual tariffs) within the Access Arrangement period. It does not constrain the total revenue that Envestra can recover from customers. Given this, the WAPC places an incentive on Envestra to grow volumes, as this will enable the business to increase its revenue recovery (higher network utilisation is also in the long term interests of Users and consumers).

The proposed WAPC formula, which is consistent with that used over the past two regulatory periods, is shown in box 15.1. The right hand side of the WAPC formula calculates the weighted average of the notional revenues determined for year ***t*** and year ***t-1***, which revenues are determined by applying the actual quantities of gas delivered in year ***t-2*** to the:

(1) tariffs proposed to apply in year ***t*** (which refers to the year where the adjusted tariffs will apply); divided by; and

(2) tariffs applied to customers in year ***t-1*** (which refers to the tariffs currently applying).

The weighted average of these notional revenues is constrained by the left hand side of the WAPC formula, which allows tariffs to increase by no more than the CPI less the X factor (as determined in chapter 12) plus a licence fee factor, which allows for tariffs to change in accordance with changes in the actual licence fee paid by Envestra.

The proposed tariff control formula is consistent with the formula applied in the 2008 to 2012 Access Arrangement period, other than the updated values of X. This forms part of Schedule 3 of the Reference Tariff Policy.

Box 15.1: FORMULA 1 - TARIFF CONTROL FORMULA

$$\frac{\sum_{i=1}^{n}\sum_{j=1}^{m} p_t^{ij} \bullet q_{t-2}^{ij}}{\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} \bullet q_{t-2}^{ij}} \leq (1+CPI_t)(1-X_t)(1+L_t)$$

where:

CPI_t	is the CPI, as defined in the glossary, for year t;
X_t	is – 0.123 for 2014;
X_t	is – 0.073 for 2015;
X_t	is - 0.073 for 2016;
X_t	is - 0.073 for 2017;
n	is the number of different Haulage Reference Tariffs;
m	is the different components, elements or variables ("components") comprised within a Haulage Reference Tariff;
p_t^{ij}	is the proposed component j of Haulage Reference Tariff ***i*** in year ***t***;
p_{t-1}^{ij}	is the prevailing component j of Haulage Reference Tariff ***i*** in year ***t – 1*** ;
q_{t-2}^{ij}	is the quantity of component j of Reference Tariff *i* sold in year ***t – 2*** (expressed in the units in which that component is expressed (eg, GJ)); and
L_t	is the Licence Fee factor as defined in box 3.

15.3.2 Licence Fee Factor

The proposed licence fee factor set out in both the tariff control formula and rebalancing control formula is the same as that applying in the 2008 to 2012 Access Arrangement period (see box 15.2). This factor allows for the actual licence fee charged by the Victorian Government to be passed through by Envestra once it is known. The licence fee factor also forms part of Schedule 3 of the Reference Tariff Policy of the 2013 to 2017 Access Arrangement.

Box 15.2: FORMULA 2 – LICENCE FEE FORMULA

L_t is the Licence Fee pass through adjustment to the Distribution price control in Calendar Year ***t***, calculated as follows:

$$L_t = \frac{(1+L'_t)}{(1+L'_{t-1})} - 1$$

where:

$$L'_t = \frac{lf_{t-1}(1+pretaxWACC_0)^{3/2}(1+CPI_t)^{3/2}}{(1+CPI_t)(1-X_t)\sum_{i=1}^{n}\sum_{j=1}^{m} p_{t-1}^{ij} q_{t-2}^{ij}}$$

L'_{t-1} is the value of L'_t determined in the Calendar Year ***t – 1***

lf_{t-1} is the licence fee paid by the distribution business for the Financial Year ending in June of the Calendar Year ***t - 1***

CPI_t is the CPI, as defined in the glossary, for year ***t***;

X_t is - 0.123 for 2014;

X_t is - 0.073 for 2015;

X_t is - 0.073 for 2016;

X_t is - 0.073 for 2017;

p_{t-1}^{j} is the prevailing component j of Haulage Reference Tariff in year ***t – 1***; and

q_{t-2}^{j} is the quantity of component j of Haulage Reference Tariff sold in year ***t–2*** (expressed in the units in which that component is expressed (eg, GJ)).

15.3.3 Rebalancing Control Mechanism

The proposed rebalancing control formula is also consistent with that used in the 2008 to 2012 Access Arrangement period, other than updated values for X and an increase in the value of the rebalancing constraint (Y) from 0.02 to 0.10 (or 10%) (see box 15.3). The increase in the rebalancing constraint is required to:

- provide Envestra with a reasonable opportunity to recovery its efficient costs (as required by the revenue and pricing principles); and
- allow Envestra to transition to the revised tariff structures in a way that effectively manages price changes to customers (as required by the National Gas Objective).

With regard to the first point, chapter 3 of this Access Arrangement Information (AAI) noted that Envestra has, over the past 10 years, been unable to recovery the benchmark revenue set by the regulator. Should this again occur, a higher rebalancing constraint would allow Envestra to limit the under-recovery of revenue by altering its tariff structures, thereby improving its ability to recover efficient costs.

A higher rebalancing constraint also allows Envestra to gradually introduce the necessary changes to reference tariffs described in chapter 14 over the 2013 to 2017 Access Arrangement period. This has the benefit of avoiding large price changes to certain customers. Envestra notes that a constraint of 10% is consistent with that approved by the AER for the New South Wales gas distributor.[195]

Box 15.3: FORMULA 3 - REBALANCING CONTROL FORMULA

The following formula applies separately to each Tariff Class

$$\frac{\sum_{j=1}^{m} p_t^{ij} \bullet q_{t-2}^{ij}}{\sum_{j=1}^{m} p_{t-1}^{ij} \bullet q_{t-2}^{ij}} \leq (1+CPI_t)(1-X_t)(1+L_t)(1+Y_t)$$

where:

CPI_t	is the CPI, as defined in the glossary, for year ***t***;
X_t	is - 0.123 for 2014;
X_t	is - 0.073 for 2015;
X_t	is - 0.073 for 2016;
X_t	is - 0.073 for 2017;
Y_t	is 0.10;
n	is the number of different Reference Tariffs;
m	is the components comprised within Haulage Reference Tariff ;
p_t^j	is the proposed component j of Haulage Reference Tariff in year ***t***;
p_{t-1}^j	is the prevailing component j of Haulage Reference Tariff in year ***t – 1***;
q_{t-2}^j	is the quantity of component j of Haulage Reference Tariff sold in year ***t – 2*** (expressed in the units in which that component is expressed (eg, GJ)); and
L_t	is the Licence Fee factor as defined in Box 3.

The intent of the rebalancing control formula is to provide price certainty to customers. The formula therefore places a constraint on the movement in individual reference tariffs, where each reference tariff can increase by 10% over and above the increase permitted by the left hand side of the tariff control formula. The rebalancing control formula forms part of Schedule 3 of the Reference Tariff Policy of the Access Arrangement.

[195] AER 2010, "*Final Decision Jemena Gas Networks Access arrangement proposal for the NSW gas networks 1 July 2010 to 30 June 2015 – June 2010*", pg. 372

15.3.4 Carbon Tariff

As noted in chapter 2, the Federal Government has introduced a price on carbon emissions to apply from 1 July 2012. The carbon price is set at $23 for each emissions unit or permit (equivalent to one tonne of carbon emissions) as at 1 July 2012, which amount is then escalated annually by the CPI plus 2.5% up until 2014/15. From 1 July 2015, the carbon price will be set by the market for carbon permits.

Envestra intends to seek a pass through under the 2008 to 2012 Access Arrangement to recover the costs associated with the introduction of the carbon price on 1 July 2012. Once approved, a separate carbon tariff will be applied to all of Envestra's customers. While this is necessary given the carbon price was introduced during a regulatory period, this approach has the advantage of providing a specific price signal to customers regarding the cost of carbon emissions.

Envestra proposes to continue with a separate carbon tariff over the 2013 to 2017 Access Arrangement period. As a result, Envestra has not included any costs associated with the introduction of the carbon price into the determination of building block revenue set out in chapter 12. Rather, the costs will be recovered through the carbon tariff, which costs include:

- the cost of the carbon permits that Envestra will need to purchase; and
- the additional cost of administering the carbon scheme.

Envestra proposes the formulae set out in box 15.4 to determine the carbon tariff. The formulae allow Envestra to set the annual carbon tariff to recover the forecast costs of the carbon scheme along with a true up mechanisms to account for the differences between forecast and actual carbon costs. The carbon tariff formulae are design so that Envestra recovers from customers no more or less than the actual costs that it incurs.

Box 15.4 – FORMULA 3 – CARBON TARIFF FORMULA

When assessing Envestra's proposed tariffs, submitted in accordance with this Access Arrangement, the AER will assess whether the Carbon Payment Revenue (CPR_t), is less than or equal to the Maximum Carbon Payment Revenue allowed ($MCPR_t$) as follows:

$$CPR_t \leq MCPR_t$$

where:

CPR_t is the total of Envestra's proposed Carbon Payment Revenue charges multiplied by the corresponding forecast quantities to be distributed for each tariff component of each tariff, in calendar year *t*.

$MCPR_t$ is the maximum revenue that Envestra is allowed to receive from its Carbon Payment Revenue tariffs from all consumers for the calendar year *t* and is expressed as:

$$MCPR_t = CPP_t - K_t$$

where:

CPP_t is the aggregate of all costs that Envestra forecasts it will incur in respect of the Carbon Scheme in calendar year *t*, and

K_t is a correction factor to account for any under or over recovery arising from actual Carbon Payment Revenue tariffs in relation to allowed revenue and is expressed as follows:

$$K_t = (Ky_t + Kz_t + K_{t-1})$$

where:

Ky_t is calculated in accordance with the formula below;

Kz_t is calculated in accordance with the formula below;

K_{t-1} is the figure calculated for K_t for calendar year *t–1*; and

Calculation of Ky_t

Ky_t is a correction factor determined with reference to the following formula:

$$Ky_t = CPR_{t-1} - CPP_{t-1}$$

where:

CPR_{t-1} is the total revenue which it is estimated Envestra will earn from its Carbon Payment tariffs in respect of all customers in calendar year *t-1*; and

CPP_{t-1} is the aggregate of all costs that Envestra estimates it will incur in respect of the Carbon Scheme in calendar year *t -1*.

Calculation of Kz_t

Kz_t is a correction factor for the difference between the estimates made when calculating *Ky* for calendar year *t-1* and the actual audited values now available. Kz_t is expressed by the formula below.

$$Kz_t = (CPRa_{t-2} - CPRe_{t-2}) - (CPPa_{t-2} - CPPe_{t-2})$$

where:

$CPRa_{t-2}$ is the actual total revenue earned by Envestra from Carbon Payment tariffs in respect of all distribution customers in calendar year t–2;

$CPRe_{t-2}$ is the figure used for CPR_{t-1} when calculating Ky_t for calendar year t-2;

$CPPa_{t-2}$ is the aggregate of all costs that Envestra actually incurred in respect of the Carbon Scheme in calendar year *t -2*; and

$CPPe_{t-2}$ is the figure used for CPP_{t-1} when calculating Kyt for calendar year t-1.

15.3.5 Transitional Measures

The tariff control, rebalancing control and licence fee formulae rely upon actual demand data from two years prior (year ***t-2***) to set the proposed tariffs for a relevant year (year ***t***). For example, the 2014 adjustment to reference tariffs requires 2012 demand data. The introduction of the new reference tariff structures complicates this calculation as the 2012 demand data will reflect the old reference tariff structure.

Envestra will therefore need to remodel the 2012 demand data to match the new reference tariff structures for the 2014 tariff adjustment. The methodology used to remodel the 2012 demand data will require detailed demand data from the billing system to be "recut" into the new tariff steps. All the relevant information used to recut the demand data will be provided to the AER at the time the 2014 reference tariffs are to be approved.

The introduction of the new reference tariffs from 2013 also gives rise to an issue in the AER's Post Tax Revenue Model (PTRM). The PTRM requires 2013 reference tariffs to be the same as the reference tariffs applying in 2012, so that the PTRM can determine the percentage change in 2012 tariffs that is required to allow for the recovery of regulatory revenue from 2013 (often referred to as a "P-nought" adjustment).

Given the difference between reference tariffs in 2012 and 2013, Envestra has developed a model whereby the 2012 reference tariffs are set to be the same as the new 2013 reference tariffs. The magnitude of the adjusted 2012 tariffs is set such that the revenue recovered from the adjusted 2012 tariffs matches the revenue recovered from the actual 2012 tariffs. The model is provided as attachment 15.1 to this AAI.

15.3.6 Tariff Variation Process

The tariff variation process is detailed in section 4.6 of the Access Arrangement and is generally consistent with that currently applying over the 2008 to 2012 Access Arrangement period. In summary, Envestra will notify the AER in respect of any variations to reference tariffs at least 35 business days before those tariffs are proposed to come into effect. The notification to the AER will provide an explanation and details of how the proposed variations have been calculated.

The AER will have 20 business days to approve or reject the proposed variations to reference tariffs. This allows market participants 15 business days to prepare for the implementation of the new tariffs. Envestra believes that this tariff variation process complies with all aspects of Rule 74 as it:

- limits administrative costs to the AER, Envestra and potential users;
- considers arrangements that have applied in the past;
- only allows for tariffs to change once during a regulatory period, aside from any cost pass through events that might arise; and
- provides adequate oversight to the AER over any proposed variations to reference tariff.

15.4 Ancillary Reference Services

Envestra proposes to maintain its Reference Tariffs for Ancillary Reference Services over the 2013 to 2017 Access Arrangement period. It is also proposed to continue to adjust those tariffs by changes in inflation.

15.4.1 Ancillary Reference Tariff Variation Mechanism

Subject to the approval of the AER, Envestra will vary the Reference Tariffs for Ancillary Reference Services on the basis of the following tariff control formula:

$$ART_t = ART_{t-1} \times CPI_t$$

where:

ART_t is the Reference Tariff that will apply to an Ancillary Reference Service in year ***t***;

ART_{t-1} is the Reference Tariff that applied to that Ancillary Reference Service in year ***t-1***; and

CPI_t is the CPI, as defined in the glossary, for year ***t***;

15.4.2 Ancillary Tariff Variation Process

The tariff variation process is proposed to mirror that used to vary Haulage Reference Tariffs (see section 15.3.6).

15.5 Cost Pass Through Events

15.5.1 General

In accordance with Rule 97(1)(c), Envestra has proposed certain cost pass through events for the 2013 to 2017 Access Arrangement period. In defining cost pass through events, Envestra has only given consideration to events:

(a) that are not within its control;

(b) for which it is unreasonable or unable to provide cost forecasts for the purposes of determining the total revenue requirement (whether it be due to the uncertainty of timing/occurrence or magnitude of the event); and

(c) that are not included in the capital or operating cost forecasts, or for which Envestra might already be compensated for through the rate of return.

The proposed Cost Pass Through Events are defined in section 4.5 of the Access Arrangement and are as follows:

(1) Regulatory Change Event -

A change in a regulatory obligation or requirement that:

(a) falls within no other category of Cost Pass Through Event; and

(b) occurs during the course of an Access Arrangement period; and

(c) affects the manner in which Envestra provides services (as the case requires); and

(d) materially increases or materially decreases the costs of providing those services.

(2) Service Standard Event -

A legislative or administrative act or decision that:

(a) has the effect of:

(i) varying, during the course of an access arrangement period, the manner in which Envestra is required to provide a reference service; or

(ii) imposing, removing or varying, during the course of an access arrangement period, minimum service standards applicable to prescribed reference services; or

(iii) altering, during the course of an access arrangement period, the nature or scope of the prescribed reference services, provided by Envestra; and

(b) materially increases or materially decreases the costs to Envestra of providing prescribed reference services.

(3) Tax Change Event –

A tax change event occurs if any of the following occurs during the course of an access arrangement period for Envestra:

(a) a change in a Relevant Tax, in the application or official interpretation of a Relevant Tax, in the rate of a Relevant Tax, or in the way a Relevant Tax is calculated;

(b) the removal of a Relevant Tax;

(c) the imposition of a Relevant Tax; and

(d) in consequence, the costs to Envestra of providing prescribed reference services are increased or decreased.

(4) Terrorism Event –

An act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear) and which materially increases the costs to Envestra of providing a reference service.

(5) Network User Failure Event –

A network user failure event means the occurrence of an event whereby an existing network user becomes insolvent or is unable to continue to supply gas to its customers, and those customers are transferred to another network user, and which materially increases the costs of Envestra providing reference services.

(6) Insurer Credit Risk

An event where the insolvency of the nominated insurers of Envestra occurs, as a result of which Envestra:

(a) incurs materially higher or lower costs for insurance premiums than those allowed for in the access arrangement; or

(b) in respect of a claim for a risk that would have been insured by Envestra's insurers, is subject to a materially higher or lower claim limit or a materially higher or lower deductible than would have applied under that policy; or

(c) incurs additional costs associated with self funding an insurance claim, which would have otherwise been covered by the insolvent insurer.

(7) Insurance Cap Event

An event that would be covered by an insurance policy but for the amount that materially exceeds the policy limit, and as a result Envestra must bear the amount of that excess loss. For the purposes of this Cost Pass-through Event, the relevant policy limit is the greater of the actual limit from time to time and the limit under Envestra's insurance cover at the time of making this access arrangement. This event excludes all costs incurred beyond an insurance cap that are due to Envestra's negligence, fault, or lack of care. This also excludes all liability arising from the Envestra's unlawful conduct, and excludes all liability and damages arising from actions or conduct expected or intended by Envestra.

(8) Natural Disaster Event

Any major fire, flood, earthquake, or other natural disaster beyond the control of Envestra (but excluding those events for which external insurance or self insurance has been included within Envestra's forecast operating expenditure) that occurs during the forthcoming access arrangement period and materially increases the costs to Envestra of providing reference services.

The above Cost Pass Through Events provide for protection in respect of events that were approved by the AER when reviewing Envestra's South Australian and Queensland access arrangements.

15.5.2 Materiality Threshold

Envestra's current cost pass through events are not subject to a specific materiality threshold. Envestra believes it should not be necessary to specify a threshold because it is of the view that:

(a) the cost of preparing a cost pass through application places a discipline on a distributor in respect of making claims;

(b) cost pass through events are, by their nature, infrequent;

(c) it is inconsistent to apply a materiality threshold to a cost pass through amount, when no such threshold exists when determining amounts to be recovered by way of forecast costs during an access arrangement review process;

(d) the costs would have been included in the forecast expenditure had they been known, regardless of their magnitude;

(e) to-date, where no defined materiality threshold has applied, Envestra has not made any frivolous claims in respect of any of its networks;

(f) the NGR otherwise require the administrative costs to be considered.

With regard to the last point, the administrative costs will vary depending upon the nature of the Cost Pass Through Event. Hence, while the NGR recognise that administrative costs are a consideration, the NGR (rightly) stops short of imposing a materiality threshold, which supports the notion that such costs (i.e. administrative versus pass through costs) should be considered on a case-by-case basis.

For all of the above reasons, Envestra considers that it is inappropriate to specify a materiality threshold.

15.6 Summary

Envestra proposes similar tariff variation mechanisms in the 2013 to 2017 Access Arrangement period to that which has applied in all previous regulatory periods. In particular, Envestra is proposing:

- the same tariff control formulae (aside from a necessary increase in the rebalancing constraint);
- the same administrative processes for the approval of variations to reference tariffs; and
- the same cost pass through events as those recently approved by the AER in respect of Envestra's South Australian and Queensland distribution networks.

The tariff variation mechanism proposed in this chapter complies with all relevant requirements of the NGR. In particular, reference tariffs are to be varied pursuant to rule 97(1) (b), the formula for varying tariffs is consistent with rule 97(2)(b) and the process for the approval of reference tariffs complies with rules 97(3), 97(4) and 97(5).

16. Non-Tariff Components

16.1 Introduction

This chapter sets out the key policy and terms governing access to the Network over the 2013 to 2017 Access Arrangement period.

16.2 Capacity Trading

The Network is operated in what was previously referred to as a "market carriage" system of managing third party access to the distribution network, whereby a Network User does not have a right to trade its right to obtain a Service to another Network User. Capacity trading is therefore not applicable to the Victorian Network.

16.3 Network Extensions

Envestra's proposed extensions policy allows for generic extensions of the network to be covered under the terms of the Access Arrangement. This is necessary if Envestra is to carry out its core business in an efficient manner. Notification or application to the AER in respect of extensions should only take place for those extensions which are significant and which were not incorporated into the approved capital expenditure forecasts for the 2013 to 2017 Access Arrangement period.

A significant extension is one that does not routinely occur within the business. It is important therefore that this be appropriately defined. If the threshold for a significant extension is set too low, it would result in the AER opining over numerous applications from distributors. Involving the AER in business decisions that are of a routine nature is not desirable or appropriate.

The following definition of a significant (or high pressure extension) takes this issue into account by ensuring that routine extensions (i.e. those extensions of the Network operating at a pressure under 1,050 kPa) are not treated as significant extensions:

> "*high pressure pipeline extension means a pipeline (operating above 1,050 kPa) that exceeds one kilometre in length and is proposed to be built to a postcode area previously not serviced by reticulated gas*"

Envestra still has parts of the network that operate at low or medium pressure. While these mains will be upgraded over time to operate at high pressure up to 515 kPa, extensions to such mains will all be treated as pertaining to the covered network. Like extensions to high pressure mains operating under 1,050 kPa, extensions to low and medium pressure mains are routine in nature and undertaken on a daily basis.

The proposed policy therefore strikes an appropriate balance of ensuring that the interests of Users are protected, while ensuring that routine extensions to the network are not subject to inappropriate or inefficient regulatory processes. Envestra notes that the proposed extensions policy for the Network is essentially the same as that recently approved by the AER for Envestra's South Australian and Queensland networks.

16.4 Terms and Conditions

16.4.1 General Approach

The General Terms and Conditions set out in Envestra's revised Victorian Access Arrangement (referred to as the Victorian General Terms) are substantially the same as the General Terms and Conditions which were included in Envestra's Access arrangements for its South Australian and Queensland networks.

The South Australian and Queensland Access Arrangements were reviewed by the AER in 2011 and the terms and conditions were revised to take account of around 40 changes required by the AER. The final terms and conditions were then approved by the AER in June 2011.

The main differences between the Victorian General Terms and the South Australian and Queensland terms and conditions relate to:

(a) changes necessary to ensure the Access Arrangement reflects the National Energy Customer Framework (NECF). These changes are discussed in section 16.4.2 below; and

(b) terms dealing with specific Victorian legislation or regulations, which are explained in section 16.4.3 below.

As part of the review of the 2003 to 2007 Access Arrangement, Envestra and the other two Victorian distributors prepared default terms and conditions for their respective Victorian networks. These terms and conditions were not identical but were substantially consistent. These terms were then used, with some modifications, in the 2008 to 2012 Access Arrangement period. Again, the terms and conditions adopted by each distributor were not identical but were substantially consistent.

However, the continued use of these terms by Envestra creates inefficiencies in relation to Envestra's Victorian gas distribution network. It means that the terms applicable to Envestra's Victorian network are different from the terms that apply to Envestra's South Australian and Queensland networks (along with that used for Envestra's uncovered networks).

Accordingly, for the 2013 to 2017 Access Arrangement period, Envestra proposes to adopt terms and conditions for Victoria that are substantially the same as the terms and conditions that Envestra uses in other jurisdictions, including that approved by the AER for its South Australian and Queensland networks. This approach will:

(a) streamline negotiations with retailers;

(b) streamline the contracting process;

(c) streamline the process of seeking legal advice in relation to the terms and conditions;

(d) enable Envestra to develop and utilise consistent internal procedures across multiple jurisdictions;

(e) streamline Envestra's response to regulatory changes;

(f) streamline the process of regulatory reviews; and

(g) reduce legal and administrative costs.

It will enable Envestra, and the gas retailers with which it contracts, to take a consistent national approach to regulation and contracting on Envestra networks.

Envestra submits that this approach therefore gives the best effect to the national gas objective and the National Gas Rules. The national gas objective, which is set out in section 23 of the National Gas Law, states that:

> *"The objective of this Law is to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas."*

The continued use of a different set of terms and conditions for Envestra's Victorian network creates unnecessary inefficiencies for Envestra and for the gas retailers who use that network and other networks or transmission pipelines owned by Envestra.

It is Envestra's goal to adopt terms and conditions in each jurisdiction that are as consistent as is possible, with variations only for differences between jurisdictions that arise from regulatory derogations or different jurisdictional tariff structures.

Envestra submits that this position also better recognises the clear regulatory trend towards consistent national gas legislation.

At the time of the 2003 to 2007 Access Arrangement period, Victorian gas legislation was sufficiently different from legislation in other States so as to make it difficult to adopt terms and conditions that were consistent with the other States that Envestra operates in. The Victorian regulatory regime was characterised by greater complexity, both in terms of the number of regulatory instruments and their content.

The introduction of the National Gas Law and National Gas Rules (in mid-2008), and now the adoption of the National Energy Customer Framework (in mid-2012), means that the gas legislation of the participating States has become more harmonised and standardised. There is now no justification for the continued use of a distinctly different set of terms and conditions in Victoria.

16.4.2 The NECF Amendments

Variation Proposals will be submitted to the AER seeking to amend the General Terms and Conditions for Envestra's Queensland and South Australian networks to reflect the NECF amendments. The proposed Victorian General Terms and Conditions incorporate these amendments.

As set out in those Variation Proposals, Envestra considers that the amendments relating to the NECF implementation are immaterial as they do no more than incorporate each party's rights and obligations under the NECF in the Access Arrangement.

16.4.3 Victorian Specific General Terms and Conditions

This section sets out those clauses in the Victorian General Terms that differ from the terms and conditions for Envestra's existing South Australian and Queensland Access as a consequence of Victorian specific legislation and regulations. Envestra has explained the rationale behind the inclusion of each of these clauses below.

Although Envestra intends to adopt a national approach to the General Terms and Conditions for each of its Access Arrangements, there will still be a need for minor differences in each jurisdiction as a result of the different instruments/regulations that apply.

Clauses 12.1 and 12.7 – Gas Specifications

The Victorian General Terms replaces the word "the" with the word "any" in the second line of clause 12.1 and deletes the last sentence in clause 12.1, which specifies the gas specifications applicable at the start of the Agreement. The Victorian *Gas Safety (Gas Quality) Regulations 2007* specify the standard to which gas must comply (which is currently AS 4564). Including a reference to that standard in the clause limits its application if the specifications were to be amended in time.

A new clause 12.7 has been inserted as follows:

> *"For the purposes of the Agreement, Gas will not meet the specifications imposed by law if it would be unlawful to sell or supply that Gas, for any reason whatsoever".*

The Victorian *Gas Safety Act 1997* and the accompanying regulations set out various instances in which it is unlawful to sell or supply gas. Clause 12.7 has been incorporated to ensure that those requirements are reflected in the specification applicable to gas provided under the Access Arrangement. It enables either party to declare gas as being off-specification gas where that party would be unable to sell or supply the gas.

Clause 28.2(d) and (i) – Termination by Envestra

A new clause 28.2(d) enables Envestra to terminate the Agreement where "an official (including, but not limited to, an administrator, manager or receiver) is appointed in respect of the business of the Network User or the whole, or any significant part of, the assets of the Network User". This clause is intended to cover the situation where, under section 41 of the Victorian *Gas Industry Act 2001*, the Essential Services Commission appoints an administrator to a licensed business where the security of gas supply is threatened by a contravention of licence conditions. It has been drafted to capture any other termination rights that may be incorporated in legislation over time rather than specifically referring to the power under section 41.

Clause 28.2(i) enables termination where Envestra ceases to hold its gas distribution licence. Clause 3 of Envestra's existing distribution licence enables the licence to be revoked where Envestra does not comply with an enforcement order or an undertaking, or where Envestra agrees to the revocation of the licence. If Envestra's licence was revoked, it would be unlawful for it to continue to provide the services on the Network and consequently should have a right to terminate where this occurs to ensure that it is not in breach of the law.

Clause 31.1(f) – Definition of Force Majeure

The amendment to clause 31.1(f) is designed to cover several scenarios.

Part 9 of the Victorian *Gas Industry Act 2001* applies where the supply of gas is likely to become less than is sufficient for the reasonable requirements of the community. Section 207 allows the Minister in those circumstances to give any directions the Minister thinks are necessary. This can include directions in relation to the distribution of gas, including prohibiting the operation of services. The inserted clause is designed to relieve Envestra of liability where it complies with a relevant direction/law and as a result would be in breach of the Agreement.

To comply with its statutory obligations under the Victorian Gas Industry Act, Envestra may need to take action that would otherwise constitute a breach of the Agreement. For example:

(a) sections 32 and 33 impose obligations on Envestra in relation to the safe operation of the Network;

(b) sections 34 and 35 impose an obligation on Envestra to not knowingly sell or supply where the installation is unsafe;

(c) section 44 obligates Envestra to comply with the Safety Case for the Network;

(d) section 90 gives an inspector the power to disconnect or seize/remove gas pipe, fittings or equipment;

(e) section 106 gives the Director power to direct a person to cease supply, disconnect a customer etc;

(f) section 107 gives the Director the power to do anything to make a gas emergency safe; and

(g) section 112 enables the Director or inspector to issue a notice prohibiting activity that impacts on the safe conveyance, sale, supply, etc. of gas.

The clause has been drafted to benefit both Envestra and the Network User, as there are many instances in which the Network User may be required to take action to comply with a statute that would (but for this new clause) result in a breach of the Agreement.

Clause 37.1 – Definition of Dispute

The amendment to the definition of dispute is designed to remove from the Access Arrangement dispute provisions any dispute for which a law requires Envestra and/or the Network User to follow a particular dispute resolution process.

For example clause 7(a)(ii) of Envestra's distribution licence requires Envestra to implement a scheme for the fair, reasonable and effective investigation and resolution of disputes between Envestra and a person aggrieved about the way in which Envestra conducts its business generally. Clause 7(b) requires Envestra to participate in an Ombudsman scheme.

Section 31 of the *Gas Industry Act 2001* gives the Essential Services Commission power to resolve disputes between the licensee and any person relating to industry codes, standards, rules and guidelines. Section 36 requires Envestra to implement a customer dispute resolution scheme.

Clause 42.1 – Interpretation

The amendments to this clause are designed to ensure that the definition of law picks up any statutory instruments or other directives that a Party is legally required to comply with.

16.4.4 Comparison of Existing Access Arrangement with the Proposed Victorian General Terms

The following table shows how and where the subject matter of each clause in the general terms and conditions of the existing Victorian Access Arrangement has been addressed in the proposed Victorian General Terms. This table has been prepared to assist the AER and Users in the assessment of the proposed Victorian General Terms.

In many cases the relevant clause/issue is dealt with in a different manner in the Victorian General Terms, though the legal effect is relatively similar. Differences represent a different drafting style as opposed to a different interpretation of the legal issues.

Existing General Terms and Conditions	Proposed Victorian General Terms
Clause 1.1 – Definitions	Definitions are contained in Section 10 of the Access Arrangement rather than in the General Terms and Conditions
Clause 1.2 – Interpretation	Clause 42
Clause 2 – Compliance with Regulatory Instruments	No equivalent clause. Envestra's advisors have reviewed all applicable Victorian regulatory instruments and have advised Envestra that the proposed Victorian General Terms are consistent with those instruments. The clause is unnecessary.
Clause 3 – Customer Relationship	No equivalent clause deemed necessary.
Clause 4.1 – Provision of Distribution Services	Clauses 2.1, 2.2, 2.6 and 20.1.
Clause 4.2 – Deemed request for Distribution Services	No equivalent clause – position is clear under Law.
Clause 4.3 – Cessation of provision of Distribution Services	No equivalent clause – position is clear under Law.
Clause 4.4 – Entitlement to refuse Service	Subclause (a) is covered in the definition of Force Majeure in clause 31. Subclause (b) is covered in clause 12.3. Subclause (c) is covered by clause 26.3.
Clause 4.5 – Suspension for supplier of last resort	Issue is covered in the definition of Force Majeure in clause 31.
Clause 4.6 – Conditions of Supply	Sub-clauses (a) to (d) do not have equivalent provisions as Envestra believes the position is clear under Law. Sub-clauses (e) and (f) are covered by clause 16.5.
Clause 4.7 – User's obligations/Capacity management	For subclause (a) refer to clause 13.1. For subclause (b) refer to clause 33. For subclause (c) refer to clause 12. Subclause (d) is dealt with through the charging framework in the Agreement.
Clause 4.8 – Title to Gas	Clauses 16.1 and 16.2.
Clause 4.9 – Custody and Control of Gas	No equivalent provision – refer to clause 16.4.
Clause 4.10 – Unaccounted for Gas	See clauses 16.6 and 28.6.
Clause 5 – Connection	No equivalent clause – covered by the NECF.
Clause 6 – Disconnection and Interruption of Customer	Clauses 17 and 18.
Clause 7.1 – Charges	Refer to clauses 3, 19 and 20.

Clause 7.2 – Retail Service Charges	No equivalent clause deemed necessary.
Clause 7.3 – GST	Clause 43.
Clause 7.4 – Distribution Services – Invoicing, Payment and Interest	Clauses 21 and 26.1.
Clause 7.5 – Adjustment of Invoices	Clause 22.
Clause 7.6 – GSL Payments	No equivalent provision – rights and obligations captured under Law.
Clause 7.7 – Disputed Invoices	Clause 23.
Clause 7.8 – Credit Support	Clause 27.
Clause 8 – Information Exchange	See generally clause 36 but no specific equivalent provision. Obligations of each party are reflected in relevant industry procedures/protocols.
Clause 9 – Communications regarding Customers and System Data	No equivalent provision. These issues will be dealt with by B2B Protocols to be agreed between distributors and retailers as part of the implementation of the NECF.
Clause 10 – Force Majeure	Clause 31.
Clause 11 – Enforcement of the Service Provider's Rights against Customers	No equivalent provision, except for clause 18 in relation to disconnection.
Clause 12 – Term and Termination	Clause 28.
Clause 13.1 – No Warranties	Clauses 29.8 and 30.
Clause 13.2 – Liability for supply	Clause 29.
Clause 13.3 – Non-operation of limitations of liability	No direct equivalent provision – see clauses 29 and 30.
Clause 13.4 – Insurance	Clause 34 for Network User and for Envestra is covered under general obligations in Agreement.
Clause 13.5 – Indemnity by the User	Clause 33.
Clause 13.6 – Exemption of Liability	Clause 33.6.
Clause 13.7 – Preservation of statutory provisions	No equivalent provision due to drafting approach that incorporates all regulatory instruments.
Clause 13.8 – Third Party Claims and Demands	No equivalent provision deemed necessary.
Clause 13.9 – No admissions	No equivalent provision deemed necessary.
Clause 14 – Dispute Resolution	Clause 37.
Clause 15 – Representations and Warranties	Clause 41.8.
Clause 16 – Notices	Clause 38.
Clause 17 – Confidentiality	Clause 36.
Clause 18 – Law and Jurisdiction	Clause 41.4.
Clause 19 – General	Clause 41.

16.4.5 Summary of Victorian General Terms Proposal

The following summary of the Victorian General Terms may assist Prospective Users in understanding aspects of the terms of access:

(1) Pursuant to section 6 of the Access Arrangement, it is a condition that a Prospective Network User enters into an Agreement with Envestra for the provision of any Network Service. The term 'Agreement' is defined in the Access Arrangement and means the entering into of a binding contractual arrangement between Envestra and a Network User. Prior to entering into an Agreement, a Prospective Network User must satisfy Envestra that it:

- has the necessary financial capacity to meet its obligations to Envestra; and
- where necessary, has adequate arrangements in place to ensure it can keep gas deliveries into and out of the Network in balance.

(2) Annexure E allows for the details pertaining to the specific circumstances of the parties entering into the agreement.

(3) Annexure F sets out the general terms and conditions that are to apply, as a minimum, to the provision of each Reference Service. It describes terms and conditions that are applicable to both Haulage and Ancillary Reference Services (Part IV of the terms and conditions), as well as those terms and conditions which apply specifically to each type of Reference Service (Part II – Haulage Reference Services, and Part III – Ancillary Reference Services).

(4) The clauses applying to Haulage Reference Services (Part II) address matters including:

- procedures for classifying Delivery Points;
- meter accuracy and reading;
- minimum Gas quality and delivery pressures;
- possession of Gas and responsibility;
- warranties and title to Gas; and
- supply curtailment.

(5) Part III applies only to the Ancillary Reference Services. This part only consists of one clause because the Retail Market Procedures deal extensively with the obligations surrounding these services.

(6) Part IV applies both to Haulage Reference Services and Ancillary Reference Services. These clauses address matters including:

- invoices and payment arrangements;
- procedures for determining delivered quantities;
- termination;

- liability and indemnities;
- relationship to the *Trade Practices Act 1974*;
- Force Majeure;
- assistance;
- access to premises;
- confidentiality;
- notices;
- assignment by the Network User;
- amendment of the Agreement; and
- other miscellaneous provisions.

The obligations, duties and responsibilities of Envestra and any Network User described in the Victorian General Terms are in addition to those established in law or by any relevant regulatory instrument. Where the Victorian General Terms described in Annexure E of the approved Access Arrangement are amended, the default position is that the Victorian General Terms applying to an existing Agreement will also change accordingly, subject to agreement with the User.

However, a Network User and Envestra may agree that all or some of the terms and conditions applicable to their Agreement will not change during the term of an Agreement, regardless of any amendments to Annexure E of the Access Arrangement. Both parties are therefore free to agree to arrangements that reflect their preferred risk profile at a point in time.

The proposed Victorian General Terms comply with the NGR because they are consistent with good industry practice and are 'reasonable' in that they:

- are essentially similar to those currently applying to Users;
- are consistent with the Terms approved by the AER to apply across Envestra's other key networks;
- are sufficiently well defined, so that the likelihood of a dispute over the terms and conditions of access is minimised; and
- are designed to protect and balance the legitimate business interests of Envestra, as well as Users and Prospective Users.