# Access Arrangement Information for the Queensland Network

# Allgas Energy Pty Ltd

**(ABN 52 009 656 446)**

**7 June 2006**

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# 1 INTRODUCTION

## 1.1 Purpose of this Document

This Access Arrangement Information document has been prepared, in accordance with section 2 of the Code, to provide Prospective Users and Users with sufficient information to understand the derivation of the Access Arrangement and its compliance with the Code.

## 1.2 Code Requirements

*2.6 Access Arrangement Information must contain such information as in the opinion of the Relevant Regulator would enable Users and Prospective Users to:*

*(a) understand the derivation of the elements in the proposed Access Arrangement; and*

*(b) form an opinion as to the compliance of the Access Arrangement with the provisions of the Code.*

*2.7 The Access Arrangement Information may include any relevant information but must include at least the categories of information described in Attachment A.*

*2.8 Information included in Access Arrangement Information, including information of a type described in Attachment A, may be categorised or aggregated to the extent necessary to ensure the disclosure of the information is, in the opinion of the Relevant Regulator, not unduly harmful to the legitimate business interests of the Service Provider or a User or Prospective User. However, nothing in this section 2.8 limits the Relevant Regulator's power under the Gas Pipelines Access Law to obtain information, including information in an uncategorised or unaggregated form.*

## 1.3 Contact Details

The contact for further details on this Access Arrangement Information is:

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## 1.4 Information Requirements

The following information is required under the Code.

*Attachment A: Information Disclosure By A Service Provider To Interested Parties*

*Pursuant to section 2.7, the following categories of information must be included in the Access Arrangement Information.*

*The specific items of information listed under each category are examples of the minimum disclosure requirements applicable to that category but, pursuant to sections 2.8 and 2.9, the Relevant Regulator may:*

- *allow some of the information disclosed to be categorised or aggregated; and*
- *not require some of the specific items of information to be disclosed,*

*if in the Relevant Regulator's opinion it is necessary in order to ensure the disclosure of the information is not unduly harmful to the legitimate business interests of the Service Provider or a User or Prospective User.*

| | |
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# 2 REVIEW OF THE REGULATORY PERIOD 2001/02 – 2005/06

## 2.1 Outcomes

The previous Allgas Access Arrangement applied from 2001/02 to 2005/06. Table 2.1 indicates the actual performance of Allgas over this period and compares these outcomes with the QCA's forecasts, as approved in the *Proposed Access Arrangement for Gas Distribution Networks: Allgas Energy Ltd and Envestra Ltd, Final Decision 2001* (QCA's Final Decision 2001*)*. This section highlights the reasons for the variances from forecast.

**Table 2.1: Summary of Previous Outcomes (2001/02 – 2005/06)**

| Average or Total outcome | QCA's Final Decision 2001 | Actual/ Forecast | Variance (+/-) | Variance (%) |
|---|---|---|---|---|
| Capital expenditure ($m nominal) | | | | |
| • Total 2002-2006 | 59.2 | 95.0 | 35.8 | 60.5% |
| • Annual average | 11.8 | 19.0 | 7.2 | 60.5% |
| Non-Capital Costs ($m nominal) | | | | |
| • Total 2002-2006 | 50.2 | 47.2 | (3.0) | (6.0%) |
| • Annual average | 10.0 | 9.4 | (0.6) | (6.0%) |
| Gas Deliveries (PJ) | | | | |
| • Total 2002-2006 | 53.2 | 49.0 | (4.2) | (8.0%) |
| • Annual average -Volume customers | 2.6 | 2.6 | 0.1 | 3.6% |
| • Annual average - Demand customers | 8.1 | 7.2 | (0.9) | (11.1%) |
| Distribution revenue ($m nominal) | | | | |
| • Total 2002-2006 | 162.6 | 165.4 | 2.8 | 1.7% |
| • Annual average - Volume customers | 22.1 | 22.6 | 0.5 | 2.3% |
| • Annual average - Demand customers | 10.4 | 10.5 | 0.1 | 0.5% |

Note: In Allgas' 2001 Access Arrangement, the two customer groups were labelled Small and Large. For this Access Arrangement, the Small and Large customer groups have been re-labelled Volume and Demand respectively.

### 2.1.1 Capital Expenditure

Allgas' capital expenditure has been significantly above the level assumed in the QCA's Final Decision 2001, with actual capital expenditure of $95.0 million, $35.8 million higher than forecast by the QCA.

A key driver of this capital expenditure has been initiated by Allgas expanding the network and connecting additional gas customers. Over the regulatory period, Allgas has been active in promoting gas reticulation, particularly through new estates with residential property developers. Since 2001, Allgas has established agreements with developers to provide gas reticulation to over 70 greenfields estates, the costs of which were not included in the QCA's original forecasts.

In addition, Allgas has successfully advanced its renewals program with significant progress in Hawthorne, Kangaroo Point, South Brisbane, West End and Toowoomba.

### 2.1.2 Non-Capital Costs

Allgas' total non-capital costs, including Unaccounted for Gas (UAG), have been slightly below the level assumed in the QCA's Final Decision 2001, at $47.2 million, $3.0 million lower than forecast by the QCA over the regulatory period.

Allgas considers that it has managed its non-capital costs in an efficient manner over the regulatory period. However, Allgas considers that certain savings are largely attributable to an allocation anomaly in years 2002/03 and 2003/04 rather than clearly identifiable out-performance of the benchmarks. As such, Allgas is not seeking to identify and retain these efficiency gains in this Access Arrangement.

### 2.1.3 Demand Growth

Over the previous regulatory period, the Allgas distribution network experienced an average total load growth of only 1.3 per cent per annum. Volume customer (Small customer group) load growth averaged 4.0 per cent or 69 TJs per annum, while for Demand customers (Large customer group), load growth averaged only 0.2 per cent or 15 TJs per annum. By 2005/06, the Allgas network transported 10,030 TJ, up from 9,559 TJ in 2000/01, with around 72 per cent being supplied to the Demand customer group and around 28 per cent being supplied to the Volume customer group.

Actual gas deliveries compared to the QCA approved forecast is outlined in Table 2.2.

**Table 2.2: Summary of Previous Gas Demand Forecasts (TJ)**

| QCA's Final Decision 2001 | 00/01 | 01/02 | 02/03 | 03/04 | 04/05 | 05/06[E] |
|---|---|---|---|---|---|---|
| Volume customers | 2,255 | 2,324 | 2,431 | 2,546 | 2,665 | 2,793 |
| Demand customers | 7,255 | 7,147 | 7,562 | 8,074 | 8,611 | 9,010 |
| Total Volume Delivered | 9,510 | 9,471 | 9,992 | 10,621 | 11,276 | 11,803 |
| **Actual Demand** | | | | | | |
| Volume customers | 2,312 | 2,406 | 2,647 | 2,578 | 2,737 | 2,817 |
| Demand customers | 7,247 | 6,944 | 7,013 | 7,183 | 7,286 | 7,213 |
| Total Volume Delivered | 9,559 | 9,350 | 9,660 | 9,761 | 10,023 | 10,030 |
| **Variance (TJ)** | | | | | | |
| Volume customers | + 57 | + 82 | + 216 | + 32 | + 72 | + 24 |
| Demand customers | (8) | (203) | (549) | (891) | (1,325) | (1,797) |
| Total Volume Delivered | + 49 | (121) | (333) | (859) | (1,253) | (1,773) |
| **Variance (%)** | | | | | | |
| Volume customers | 2.5 | 3.5 | 8.9 | 1.3 | 2.7 | 0.9 |
| Demand customers | (0.1) | (2.8) | (7.3) | (11.0) | (15.4) | (19.9) |
| Total Volume Delivered | 0.5 | (1.3) | (3.3) | (8.1) | (11.1) | (15.0) |

[E] Estimated

As shown, actual gas deliveries to Volume customers has exceeded the QCA approved forecast by between 1.3 per cent and 8.9 per cent. However, for Demand customers, actual gas deliveries fell to 19.9 per cent below the approved QCA forecast in 2005/06.

*Volume Customer Class*

Actual Volume customer growth was largely consistent with the QCA approved demand forecasts over the regulatory period. This consistency between actual and forecast growth for the Volume customer group was achieved due to:

- the effectiveness of Allgas' capital investment in growing the load on the network for this group of customers; and
- the growth in domestic households in south east Queensland over the same period.

Over the regulatory period, Allgas' capital spend on the gas distribution network has averaged approximately $19 million per annum, which is $7.2 million per annum more than forecast in the previous Access Arrangement. This increased capital investment was required to drive customer connections within new or greenfields residential developments.

From 2000/01 to 2005/06, growth in net connections (new connections less disconnections) has averaged 1,350 per annum or around 2.2 per cent.

*Demand Customer Class*

As Table 2.2 illustrates, actual growth in the Demand customer group has fallen well below the QCA approved forecast with average load growth of 0.2 per cent to 2004/05, almost 20 per cent below the original forecasts. Importantly, given the current estimate for year end consumption for the Demand customer group is 7,213 TJ, then actual load growth for this customer group has fallen over the access arrangement period.

The substantial divergence between initial forecasts and actual load growth for the Demand customer group can be explained by the underlying demand characteristics of these customers, notably that the quantum of Demand customers' expenditure on energy sources provides a strong incentive to:

- seek efficiencies in production processes which acts as a cap on growth, and occasionally results in facility rationalisation; and
- continually examine the cost competitiveness of energy substitutes.

Evidence of these drivers on the Demand customer group is the closure of many industrial sites that were connected to the Allgas Network such as:

- PGH (closed December 2001);
- BHP Steel (closed June 2002);
- Country Bake (closed October 2003);
- Buttercup Bakeries (closed May 2004); and
- Logan Textiles (closed April 2005).

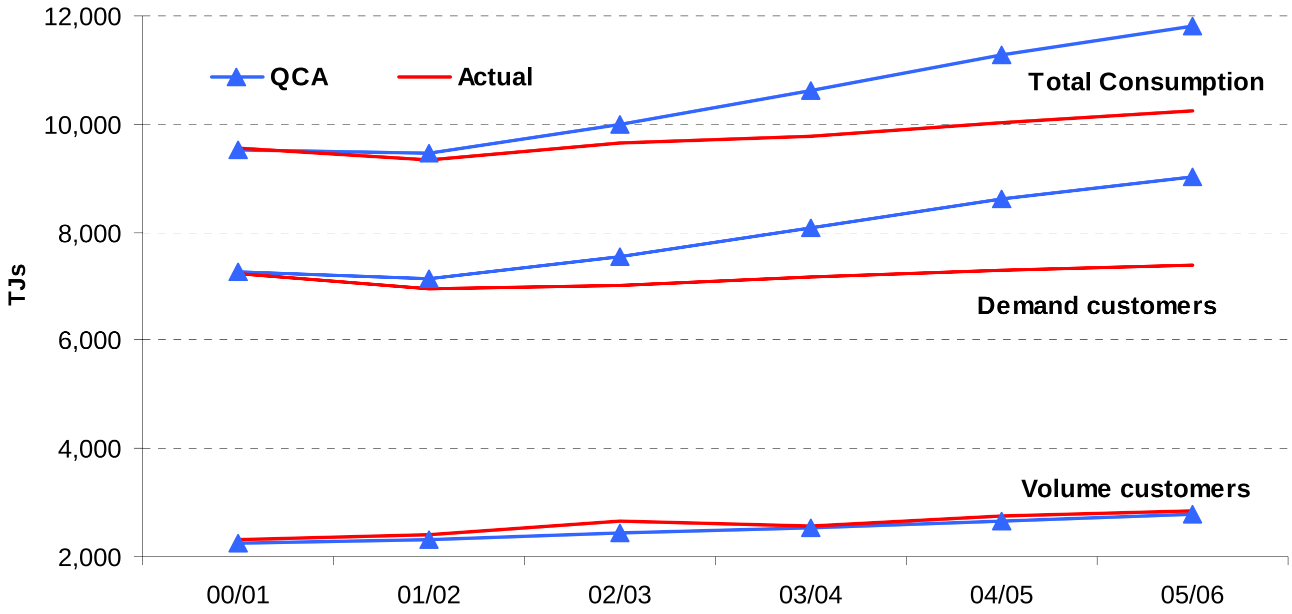
These customers consumed over 200 TJ per annum in total.

Moreover, the majority of the businesses in the Demand customer group compete in markets that would be considered mature in structure, hence, are characterised by:

- flat demand inline with economic growth, but with a general downward bias; and
- increasing pressure for cost minimisation associated with long-term erosion in profit margins, which, over time, requires firms to look for increased levels of capital intensity, i.e. greater economies of scale in production.

The impact of these factors resulted in actual demand for this customer group being well below the initial forecast. Figure 1 compares actual consumption against the QCA approved forecasts for Volume and Demand customer groups. As clearly shown, the actual consumption of the Volume customer class is similar to the QCA forecast but the consumption in the Demand customer class is well below forecast.

**Figure 1: Gas Consumption, by Customer Class**




### 2.1.4 Distribution Revenue

Over the Access Arrangement period, Allgas has been able to recover $2.8 million more in distribution network charges than expected in the QCA's Final Decision 2001.

The increase in revenue is due to several factors including:

- actual load growth in the Volume customer class has exceeded forecasts which, under a price cap, produces increased revenue;
- additional fees were added to the network charges to account for new government fees and charges that arose during the period; and
- notwithstanding the large shortfall in Demand customer consumption growth, the impact on Allgas revenue was mitigated by the sustained levels of Maximum Daily Quantities (MDQs) which are used in the network prices for this customer class.

# 3 DEMAND FORECASTS

This section describes the process by which Allgas' Demand forecasts were developed and then details the forecasts from 2006/07 to 2010/11 for the Access Arrangement.

The total demand forecast for Allgas has been developed by:

- forecasting growth in incremental customer numbers;
- using average gas consumption for residential and commercial customers in the Volume Customer class;
- estimating gas consumption, Maximum Daily Quantities (MDQs) and Maximum Hourly Quantities (MHQs) for individual customers in the Demand customer class by pricing zone; and
- aggregating the Volume and Demand customer forecasts as total gas consumption for the Allgas network.

## 3.1 Queensland Gas Market

In 1973/74, natural gas held a 6.6 per cent share of the national energy market but by 2003/04, this share had risen to 17.5 per cent. This large increase has primarily been due to:

- expansion of gas transmission pipelines;
- an increase in natural gas production (for example Coal Seam Methane);
- capital investment in industry and electricity generation using gas; and
- the environmental advantages of natural gas and subsequent government incentives (13% scheme) for use.

At present, the Queensland gas market consumes about 10 per cent of Australia's natural gas. A comparison of gas consumption, by sector, in Australia and Queensland is shown in Table 3.1.

**Table 3.1: Natural Gas Consumption 2003/04**

| | Australia (%) | Queensland (%) |
|---|---|---|
| Industrial | 57.9 | 65.4 |
| Residential | 12.4 | 1.4 |
| Electricity generation | 25.6 | 32.9 |
| Commercial | 4.1 | 0.3 |

Source: ABARE 2005

Gas consumption in Australia is dominated by the industrial sector. This is especially true in Queensland where industrial and electricity generation consumes over 98 per cent of final gas production. The residential sector consumes only 1.4 per cent. Two large industrial customers constitute almost 70% of the gas demand in the Queensland industrial sector but their gas is purchased directly from producers not through gas distribution networks. In reality, less than a quarter of gas sales in Queensland are delivered through a distribution network.

### 3.1.1 Industrial Sector

The industrial sector consists of relatively few, but large users of natural gas. Invariably, the manufacturing sector has the highest consumption of natural gas, requiring gas within production processes. For instance:

- glass, brick and cement industries, in which gas is used to generate process heat for kilns;
- metal production industries, where gas is used to generate process heat for refineries and ore smelters; and
- the chemical industry, where gas is used as a feedstock for fertilisers and plastics.

Accordingly, the underlying profitability and ongoing serviceability of the natural gas distribution network is characterised by inter-dependence, where the relationship between asset owner and customer is held in balance by:

- the network operators' need to retain the large customer on the network;
- the large industrial customers' incentive to minimise cost, but to ensure ongoing surety of supply;
- large industrial customers with Australia-wide or international operations, pursuing consolidation of operations to improve profit margins; and
- increasing environmental and community safety pressures requiring industrial production processes to be located away from built-up residential areas.

### 3.1.2 Commercial Sector

The commercial sector utilises natural gas for cooking, hot water, steam raising and heating. In the commercial sector, competition between gas and electricity is a major determinant of market share. It is likely to intensify in the future as a result of microeconomic reforms being implemented (deregulation of the respective markets) and major new infrastructure developments.

At present, there are limited possibilities for substitution of natural gas for electricity in many commercial applications. Areas where natural gas has a demonstrated price advantage are in small-scale co-generation in hospitals, new or improved gas technology in space heating and cooling, and the traditional markets of water heating and cooking. However, the opportunities where electricity can easily substitute for gas are limitless.

Recent changes in local government planning, most notably the Brisbane City Council's urban re-development strategies, and more recently the Queensland Government's Draft *South East Queensland Regional Plan*, provides greater guidance on where new or increased commercial demand for natural gas will emerge in south east Queensland. For example, the noted urban redevelopment plan for the suburbs of Hawthorne and Bulimba will provide the opportunity for natural gas to be a viable alternative to other energy substitutes as the commercial sector grows to cater for the expected increase in population, which is being driven by the marked increase in population density.

### 3.1.3 Residential Sector

Residential gas consumption in Australia is concentrated in the southern states which have high gas availability through gas distribution networks and where it is driven by the high penetration of gas heating appliances, which is needed in the cooler climates. In particular, Victorian households account for almost 70 per cent of total Australian residential gas consumption.

Queensland has a large percentage of households with no heating, and households with heating rely predominantly on electricity. Queensland residential demand for natural gas is growing where pipeline coverage and population has increased. However, household gas usage remains low in south east Queensland. For instance, the average annual residential consumption for south east Queensland is 13.6 GJ compared to 52 GJ in Victoria.

### 3.1.4 New Gas Sources

There are several possible alternative supplies of gas for Queensland that may come on-stream in the future. These include the mooted pipelines from Papua New Guinea and the Timor Sea, as well as increased production of coal seam methane in central Queensland.

Any of these options has the potential to significantly increase the supply of gas to Queensland and encourage the development of energy intensive industries and gas-powered electricity generation in the region. Furthermore, a lower cost of gas could substantially improve the relative price advantage of gas over other energy substitutes. However, given the long lead times needed to plan and construct facilities for production, storage and transportation of gas these projects are not expected to be on line in the short-term.[1]

For the purpose of Allgas' demand projections, it is assumed that no new sources of gas will become available before 2011.

## 3.2 Allgas Gas Distribution Market

### 3.2.1 Brisbane

Brisbane has a total population of over 1.3 million people and average population growth of over 2 per cent. The Allgas natural gas distribution pipelines are in South Brisbane and are well established. For the aged pipelines already in place, Allgas has to rely on new industry, increased urban population and increased market penetration for volume growth.

There are over 44,000 domestic customers connected to the Brisbane Network with annual average usage of 12 GJ/pa per site but market share is less than 8 per cent. Allgas is pursuing increased market penetration through its capital renewal projects in older suburbs of Brisbane. The renewal of low-pressure mains is allowing residential customers to utilise new appliances and additional residential unit or commercial complexes to be added to the Network. Increased market penetration of hot water heating is expected to raise household consumption over time.

### 3.2.2 Toowoomba and Oakey

Toowoomba and Oakey have a population of approximately 95,000. It is an area of low population growth and the Toowoomba gas distribution network is well established. The volume of gas distributed in the region is 15 per cent the size of the gas load in Brisbane. Large industrials are still the primary customers with 60 per cent of consumption but residential customers have a greater share than in the Brisbane region, in part due to the higher average household usage of 20 GJ per annum, which reflects the increased use of gas for heating purposes.

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[1] Allgas' network is supplied from the Roma to Brisbane transmission pipeline which operated by APT. The gas transmission pipeline is capacity constrained particularly within those pipeline sections that traverse through built-up urban areas in Brisbane. To increase the capacity of the gas transmission pipeline, for instance to support increased industrial load, would require looping of the gas transmission pipeline in built up urban areas which is estimated to require substantial up-front investment given easement issues.

### 3.2.3 South Coast

The South Coast is an area of 1,400 $km^2$ and has approximately 600,000 inhabitants. Since the late 1990s, the South Coast area has experienced average population growth of around 3% which is well above the state growth rate of 1.7%. The Allgas distribution system on the Gold Coast was only established around 1989. As a relatively new extension to the Network, most initial connections were for industrial and commercial purposes with these sectors currently accounting for 90 per cent of gas deliveries.

The South Coast region also represents the primary areas of Allgas' Network Development Plan. The plan aims to increase network utilisation by identifying and defining key opportunities where Allgas can expand the network to supply new residential and multi-residential estates. Allgas' South Coast region encompasses some of the fastest growing suburbs in south east Queensland.

## 3.3 Incremental Customer Numbers

Allgas' forecasts for growth in customer connections were prepared on the basis that:

- new connections within the Volume customer group will be driven by Allgas' network development plan; and
- there will be little incremental growth in the Demand customer group, that is, future growth will be consistent with recent historic experience.

### 3.3.1 Volume Customers - New Connections

The aim of the Allgas' network development plan is to pursue residential volume customers by ensuring that new residential developments convert to natural gas connections that take the full natural gas product bundle – cooking and hot water. The approach seeks to build the residential load in a manner that reduces the average unit cost of supplying natural gas across the whole network.

The network development plan achieves this by only expanding the network where natural gas will have a 100 per cent penetration in new residential developments, and these new residential developments take the full natural gas bundle. This ensures that any expansion to the network will be earnings positive.

Accordingly, the expected growth in new residential connections and volume represents a bottom-up assessment of demand, as determined by forecasting the actual numbers and timing of new residential connections expected to emerge as a result of agreements with developers.

Table 3.2 sets out Allgas' forecast growth in customer connections for the Volume customer group.

**Table 3.2: Forecast Volume Customer Numbers**

| | 06/07 | 07/08 | 08/09 | 09/10 | 10/11 |
|---|---|---|---|---|---|
| New connections | 2,703 | 2,886 | 3,129 | 3,454 | 4,047 |
| In-fill connection growth | 115 | 115 | 115 | 115 | 115 |
| Estimated disconnections | (473) | (477) | (481) | (483) | (483) |
| Net increase | 2,345 | 2,524 | 2,763 | 3,086 | 3,679 |
| **Total connections at 30 June** | **68,910** | **71,434** | **74,197** | **77,283** | **80,962** |
| **Annual Change** | **3.5%** | **3.7%** | **3.9%** | **4.2%** | **4.8%** |

The key risks associated with forecasting new Volume customer connections are:

- expected timing of new Volume demand may not emerge as currently expected, despite any developer guarantees of 100 per cent natural gas penetration, because consumption will only occur when dwellings are built;
- demand for residential housing stock may fall;
- commercial and industrial connections do not emerge as currently forecast; and
- natural gas does not remain price and service competitive with alternative energy sources.

### 3.3.2 Demand Customer Group - New Connections

Growth in connections from large commercial and industrial customers will occur as a result of organic growth and natural attrition on the network. Since 1996/97, large demand customer growth has tended to be one or two customers, largely in the Gold Coast region. However, growth in new customers has been balanced by complete closures or rationalisations of existing customers, most notable in the Toowoomba and Brisbane parts of Allgas' distribution area, with the net result being little change in the number of Demand customers.

Accordingly, Allgas has forecast a net gain of a single large customer per annum to 2010/11. The basis of Allgas' forecasts in relation to large commercial and industrial customers is supported by two broad factors:

- the availability and competitiveness of substitutes; and
- the continued energy efficiency of new production processes.

Greater explanation of the underlying factors driving growth in the Demand customer group is contained in section 2.1.3. Table 3.3 sets out the forecast growth in connections for the Demand customer group.

**Table 3.3: Forecast Demand Customer Numbers**

| | 06/07 | 07/08 | 08/09 | 09/10 | 10/11 |
|---|---|---|---|---|---|
| At 30 June | 113 | 114 | 115 | 116 | 117 |
| Annual Change | 0.8% | 0.8% | 0.8% | 0.8% | 0.8% |

## 3.4 Volume Customer Load Forecasts

Consumption of natural gas by residential households ranges from 0 GJ to 25 GJ per annum. Natural gas utilisation of 0 GJ to 3 GJs reflects gas consumption for cooking only. The maximum consumption of 25 GJ for residential customers reflects gas consumption that includes cooking, water heating, outdoor connections for BBQs, and heating need, which is largely confined to the Toowoomba region given climatic conditions.

For the purposes of forecasting the load from the Volume customer group, the following average consumption figures were adopted:

- 13.6 GJ per annum for residential consumers; and
- 420 GJ per annum for commercial and industrial consumers.

**Table 3.4: Forecast Consumption by Volume Customers (TJ)**

| Net Annual Increase | 06/07 | 07/08 | 08/09 | 09/10 | 10/11 |
|---|---|---|---|---|---|
| Residential | 28.3 | 30.6 | 33.1 | 36.8 | 44.0 |
| Commercial | 70.7 | 78.1 | 86.9 | 90.9 | 92.6 |
| Total growth | 99.0 | 109.7 | 121.1 | 128.7 | 137.6 |
| **Annual Load** | | | | | |
| Residential | 1,009 | 1,039 | 1,072 | 1,109 | 1,153 |
| Commercial | 1,974 | 2,052 | 2,139 | 2,230 | 2,323 |
| **TOTAL** | **2,983** | **3,091** | **3,211** | **3,339** | **3,476** |
| **Growth (%)** | **3.5%** | **3.7%** | **3.9%** | **4.0%** | **4.1%** |

Net Annual Increase equals new connections plus in-fill connections less disconnections.

## 3.5 Demand Customer Load Forecasts

There are currently 111 Demand customers with gas consumption over 10,000 GJ per annum. Historically, Demand customers on Allgas' gas distribution network have accounted for around 75 per cent of total annual gas transported. Accordingly, growth in Demand customer loads, and changes to Demand customer numbers have a disproportionate impact on Allgas' total load growth.

For gas network planning, particularly setting future operating and capital costs, the total gas load is less important. The level of activity on the gas network, that is utilisation of the gas network, is far more important as it determines the 'right-sizing' of assets, which, in turn, directly impacts on the level of capital expenditure needed, and the operating costs needed to service and maintain capital.

For gas networks, the level of activity on the gas network is determined by Maximum Daily Quantity (MDQ) and Maximum Hourly Quantity (MHQ). Forecasting the gas network's utilisation using MDQ and MHQ requires examination of the level of consumption for specific Demand customers.

This section sets out Allgas' forecasts of total load, MDQ and MHQ for Demand customers to 2010/11. The load forecasts for Demand customers incorporated the use of historic rates of growth, which were cross-checked by analysing the impact of general economic growth, and expected or known rationalisation or closures of existing large customers within the Demand customer group, and expected connections. These load forecasts provided the basis for making MDQ and MHQ forecasts for the network, which also incorporated the growth assumption of an additional Demand customer per annum.

Historically, actual Demand customer growth averaged 0.2 per cent per annum (to 2004/05), despite the economic growth rate for Australia and Queensland averaging close to 4 per cent per annum. Accordingly, Allgas has forecast growth in consumption for existing customers in the Demand customer group by adopting the following assumptions:

- total growth in gas deliveries to Demand customers is assumed to be 1 per cent on the Network;
- that MHQ will remain constant to 2010/11; and
- that MDQ will grow at 1 per cent per annum across the network.

Table 3.5 shows the forecast consumption, MDQ and MHQ for the Demand customer group to 2010/11.

**Table 3.5: Demand Customers Capacity Forecast**

| | 06/07 | 07/08 | 08/09 | 09/10 | 10/11 |
|---|---|---|---|---|---|
| Total Quantity (TJ) | 7,355 | 7,443 | 7,533 | 7,623 | 7,714 |
| Growth (%) | - | 1.2 | 1.2 | 1.2 | 1.2 |
| MHQ (GJ of MHQ) | 2,337 | 2,337 | 2,337 | 2,337 | 2,337 |
| Growth (%) | - | - | - | - | - |
| MDQ (GJ of MDQ) | 30,345 | 30,628 | 31,022 | 31,418 | 31,817 |
| Growth (%) | - | 0.9 | 1.2 | 1.2 | 1.2 |

## 3.6 Total Allgas Demand

Allgas considers that bottom-up forecasts for both Volume and Demand customers, cross-checked against the historic rates of growth, represent the best approach to estimating the future growth for Allgas' gas distribution.

In order to determine the best estimates of future growth, Allgas adopted the following forecast assumptions:

- incremental growth in residential and commercial and industrial demand from net connection forecasts (Table 3.2) is based on the Allgas network development plan;
- consumption for new connections assumed to be 13.6 GJ for residential and 420 GJ for Volume commercial and industrial customers;
- only 1 new Demand customer connects per year; and
- consumption by new connections is assumed to emerge equally over a year.

In summary, Table 3.6 indicates that:

- growth in Demand customers' consumption will be 1 per cent, which is higher than the historic experience;
- growth in Volume customers' consumption will average 3.8 per cent compared to the historic average of 4.3 per cent over the last 5 years. This reflects growth in new connections from new residential housing, and the ongoing effectiveness of Allgas' network development plan; and
- total growth will increase from 1.3 per cent in 2006/07 to 2.1 per cent in 2010/11.

**Table 3.6: Allgas Demand Forecasts to 2010/11 (TJ)**

| Year ending 30 June | 06/07 | 07/08 | 08/09 | 09/10 | 10/11 |
|---|---|---|---|---|---|
| Volume Customers | 2,983 | 3,091 | 3,211 | 3,339 | 3,476 |
| Demand Customers | 7,355 | 7,443 | 7,533 | 7,623 | 7,714 |
| **TOTAL** | **10,338** | **10,534** | **10,744** | **10,962** | **11,190** |
| **Growth (%)** | **2.7%** | **1.9%** | **2.0%** | **2.0%** | **2.0%** |

Allgas will report to the regulator by no later than 30 September of each year on performance against forecasts for the previous financial year of gas demand on an aggregate (whole of covered Network) basis and for each customer class.

# 4 CAPITAL BASE

This section describes the determination of the capital base used for the Allgas revenue forecast.

## 4.1 Code Requirements

*8.9 Sections 8.15 to 8.29 then describe the principles to be applied in adjusting the value of the Capital Base over time as a result of additions to the capital assets that are used to provide Services and as a result of capital assets ceasing to be used for the delivery of Services. Consistently with those principles, the Capital Base at the commencement of each Access Arrangement Period after the first, for the Cost of Service methodology, is determined as:*

*(a) the Capital Base at the start of the immediately preceding Access Arrangement Period; plus*

*(b) subject to sections 8.16(b) and sections 8.20 to 8.22, the New Facilities Investment or Recoverable Portion (whichever is relevant) in the immediately preceding Access Arrangement Period less*

*(c) Depreciation for the immediately preceding Access Arrangement Period; less*

*(d) Redundant Capital identified prior to the commencement of that Access Arrangement Period,*

*and for the IRR or NPV methodology, is determined as:*

*(e) subject to sections 8.16(b) and sections 8.20 to 8.22, the Residual Value assumed in the previous Access Arrangement Period; less*

*(f) Redundant Capital identified prior to the commencement of that Access Arrangement Period,*

*subject, irrespective of which methodology is applied, to such adjustment for inflation (if any) as is appropriate given the approach to inflation adopted pursuant to section 8.5A.*

## 4.2 Initial Capital Base

The initial opening capital base for the Allgas system and non-system assets was $202.6 million as at 1 July 2001. This was valued using the application of a DORC approach in the previous Allgas Access Arrangement.

**Table 4.1: Summary of Initial Capital Base ($m)**

| Asset Group | As at 1 July 2001 |
|---|---|
| System assets | 198.1 |
| Non-system assets | 4.5 |
| **Total Assets** | **202.6** |

## 4.3 Depreciation

### 4.3.1 Code Requirements

*8.32 The Depreciation Schedule is the set of depreciation schedules (one of which may correspond to each asset or group of assets that form part of the Covered Pipeline) that is the basis upon which the assets that form part of the Capital Base are to be depreciated for the purposes of determining a Reference Tariff (the* ***Depreciation Schedule****).*

*8.33 The Depreciation Schedule should be designed:*

*(a) so as to result in the Reference Tariff changing over time in a manner that is consistent with the efficient growth of the market for the Services provided by the Pipeline (and which may involve a substantial portion of the depreciation taking place in future periods, particularly where the calculation of the Reference Tariffs has assumed significant market growth and the Pipeline has been sized accordingly);*

*(b) so that each asset or group of assets that form part of the Covered Pipeline is depreciated over the economic life of that asset or group of assets;*

*(c) so that, to the maximum extent that is reasonable, the depreciation schedule for each asset or group of assets that form part of the Covered Pipeline is adjusted over the life of that asset or group of assets to reflect changes in the expected economic life of that asset or group of assets; and*

*(d) subject to section 8.27, so that an asset is depreciated only once (that is, so that the sum of the Depreciation that is attributable to any asset or group of assets over the life of those assets is equivalent to the value of that asset or group of assets at the time at which the value of that asset or group of assets was first included in the Capital Base, subject to such adjustment for inflation (if any) as is appropriate given the approach to inflation adopted pursuant to section 8.5A).*

### 4.3.2 Asset Lives

Individual asset categories are grouped together to calculate depreciation and return on assets. The lives for each of the asset groupings are set out below.

**Table 4.2: Asset Lives**

| Assets | | Lives (years) |
|---|---|---|
| Mains and Services | | |
| | Cast Iron | 80 |
| | Steel - protected<br>- unprotected | 105<br>45 |
| | PVC<br>PE<br>Copper | 30<br>80<br>85 |
| Meters | | |
| | Domestic/Commercial | 25 |
| | Commercial/Industrial | 30 |
| Gates and Sub-gates | | 50 |
| District regulators | | 50 |
| IT equipment | | 5 |
| Vehicle and other non-system | | 10 |

### 4.3.3 Depreciation Calculation

Allgas has utilised a straight-line approach in the determination of depreciation for the capital base. The straight-line approach is appropriate since:

- depreciation is allocated according to the expectation of assets' usage over the economic life of the assets;
- depreciation is stable over the life of the assets and therefore will not result in price shocks;
- it is simple, transparent and readily determined; and
- it is widely used and accepted throughout the gas industry and other regulated industries.

Forecast depreciation from the previous Allgas Access Arrangement has been adjusted for actual inflation and used in the roll-forward of the capital base. These figures are shown in Table 4.3.

**Table 4.3: Historic Depreciation Adjusted for Actual Inflation ($m Nominal)**

| | 01/02 | 02/03 | 03/04 | 04/05 | 05/06 |
|---|---|---|---|---|---|
| Depreciation | 4.7 | 5.1 | 5.2 | 5.3 | 5.6 |

Depreciation for this Access Arrangement period is determined by:

- taking the base year depreciation and escalating it for asset indexation as appropriate;
- calculating the depreciation associated with Allgas' additional capital expenditure from 2001/02 to 2005/06 using a straight-line approach;
- calculating the depreciation associated with Allgas' new capital expenditure from 2006/07 to 2010/11 using a straight-line approach; and
- summating these figures to produce a forecast for depreciation over the next 5 year period. The resulting annual depreciation projections are as shown in Table 4.4.

**Table 4.4: Future Depreciation ($m Nominal)**

| Year ending 30 June | 06/07 | 07/08 | 08/09 | 09/10 | 10/11 |
|---|---|---|---|---|---|
| Depreciation | 8.1 | 9.5 | 10.4 | 11.4 | 11.9 |

## 4.4 Capital Expenditure

The following key drivers of capital expenditure have been identified by Allgas:

- **Customer Driven Works** – these are works associated with new or upgraded connections for customers. These works include laying mains, service and metering installations and miscellaneous other works.
- **Network Augmentation Works** – these are works required to augment the existing system to ensure that safety, environmental and other service standards are maintained. This work includes mains replacement, new mains, regulator and gate station upgrades, telemetry works and miscellaneous other works.
- **Mains Renewal Service Programs** – these are major renewals programs to replace or insert existing mains where the existing mains need to be replaced generally due to: ageing; unacceptable UAG levels; and to accommodate and encourage new customer connections by providing improved gas pressure as required by many modern gas appliances.

- **Non-system Asset Expenditure** – these are additional assets required to carry out the management of the gas network. These assets include land, vehicles, plant and a variety of equipment (eg. PCs and IT systems).

### 4.4.1 Code Requirements

*8.15 Capital Base for a Covered Pipeline may be increased from the commencement of a new Access Arrangement Period to recognise additional capital costs incurred in constructing, developing or acquiring New Facilities for the purpose of providing Services (**New Facilities Investment**).*

*8.16 (a) Subject to sections 8.16(b) and sections 8.20 to 8.22, the Capital Base may be increased under section 8.15 by the amount of the actual New Facilities Investment in the immediately preceding Access Arrangement Period provided that:*

*(i) that amount does not exceed the amount that would be invested by a prudent Service Provider acting efficiently, in accordance with accepted good industry practice, and to achieve the lowest sustainable cost of providing Services; and*

*(ii) one of the following conditions is satisfied:*

*(A) the Anticipated Incremental Revenue generated by the New Facility exceeds the New Facilities Investment; or*

*(B) the Service Provider and/or Users satisfy the Relevant Regulator that the New Facility has system-wide benefits that, in the Relevant Regulator's opinion, justify the approval of a higher Reference Tariff for all Users; or*

*(C) the New Facility is necessary to maintain the safety, integrity or Contracted Capacity of Services.*

*8.17 For the purposes of administering section 8.16(a)(i), the Relevant Regulator must consider:*

*(a) whether the New Facility exhibits economies of scale or scope and the increments in which Capacity can be added; and*

*(b) whether the lowest sustainable cost of delivering Services over a reasonable time frame may require the installation of a New Facility with Capacity sufficient to meet forecast sales of Services over that time frame.*

*8.18 A Reference Tariff Policy may, at the discretion of the Service Provider, state that the Service Provider will undertake New Facilities Investment that does not satisfy the requirements of section 8.16(a). If the Service Provider incurs such New Facilities Investment, the Capital Base may be increased by that part of the New Facilities Investment which does satisfy section 8.16(a) (the **Recoverable Portion**).*

*8.20 Consistent with the methodologies described in section 8.4, Reference Tariffs may be determined on the basis of New Facilities Investment that is forecast to occur within the Access Arrangement Period provided that the New Facilities Investment is reasonably expected to pass the requirements in section 8.16(a) when the New Facilities Investment is forecast to occur.*

*8.21 Relevant Regulator may at any time at its discretion agree (with or without conditions or limitations) that actual New Facilities Investment by a Service Provider meets, or forecast*

*New Facilities Investment proposed by a Service Provider will meet, the requirements of Section 8.16(a), the effect of which is to bind the Relevant Regulator's decision when the Relevant Regulator considers revisions to an Access Arrangement submitted by the Service Provider. Before giving any agreement under this section 8.21, the Relevant Regulator must conduct public consultation in accordance with the requirements for a proposed revision to the Access Arrangement submitted under section 2.28. For the avoidance of doubt, if the Relevant Regulator does not agree under this section that the New Facilities Investment meets, or (in the case of forecast New Facilities Investment) will meet, the requirements of section 8.16(a), the Relevant Regulator may consider whether those requirements are met when it considers revisions to an Access Arrangement submitted by the Service Provider.*

*8.22 For the purposes of calculating the Capital Base at the commencement of the subsequent Access Arrangement Period, either the Reference Tariff Policy should describe or the Relevant Regulator shall determine when the Relevant Regulator considers revisions to an Access Arrangement submitted by a Service Provider, how the New Facilities Investment is to be determined for the purposes of section 8.9. This includes how the Capital Base at the commencement of the next Access Arrangement Period will be adjusted if the actual New Facilities Investment or Recoverable Portion (whichever is relevant) is different from the forecast New Facilities Investment (with this decision to be designed to best meet the objectives in section 8.1).*

### 4.4.2 Capital Expenditure from 2001/02 to 2005/06

Allgas' capital expenditure has been significantly above the level assumed in the QCA's 2001 Final Decision, with actual capital expenditure over the period of $95 million, which is $35.8 million higher than approved by the QCA.

A key driver of Allgas' capital expenditure was customer initiated expenditure. Over the regulatory period, Allgas has been active in promoting gas reticulation, particularly through new estates with residential property developers. Since 2001, Allgas has established agreements with residential developers to provide gas reticulation to over 70 greenfields estates, the costs of which were not included in the QCA's approved capital allowance. As shown in Table 4.5, almost $25 million in additional customer requested capital expenditure has been spent by Allgas over the period.

Allgas has also exceeded the allowance for augmentation capital expenditure over the regulatory period by $10.3 million, principally as a result of the South Coast project.

The South Coast project involves two steps. The first was the installation and upgrade of network in the south coast region reflected by expenditure of $1.5 million and $1.8 million in years 2001/02 and 2003/04 respectively. The second phase will involve an upgrade in capacity for the supply to the South Coast through the South Coast Pipeline.

Presently, the South Coast is supplied from Gowan Road Gate Station at Runcorn. Runcorn is limited in its ability to satisfy future demand as a result of capacity constraints at this point on the Roma to Brisbane pipeline. To ease this capacity constraint, Allgas will construct a 12.9km pipeline from Ellen Grove Gate Station to Browns Plains and an additional 10.2km pipeline from Browns Plains to the South Coast Pipeline. Supply constraints will be alleviated because the Brisbane to Roma pipeline is double looped up to Ellen Grove (and single looped to Runcorn).

With respect to the additional customer initiated and augmentation expenditure, Allgas has been cognisant of satisfying the Code criteria for efficiency and prudency and has subject all proposed expenditure to a prudence test. Furthermore, Allgas has outsourced its capital works program through a public tender process, thereby obtaining a market price with respect to the provision of these services.

In addition, Allgas continued to progress with its renewal program. However, Allgas did not meet its QCA forecast renewal expenditure during the regulatory period as a result of the extensive customer driven works undertaken on the Allgas Network. Some of the program of works proposed in its 2001 Access Arrangement has been delayed and will be performed by Allgas in the next regulatory period.

While the renewal program has provided the opportunity for increased load growth on the network, the most important outcome from the renewal program is that it ensures enhanced security and safety of gas supply in established network areas.

**Table 4.5: Past Capital Expenditure Summary ($m Nominal)**

| QCA Decision | 01/02 | 02/03 | 03/04 | 04/05 | 05/06 |
|---|---|---|---|---|---|
| Customer Requested | 5.5 | 5.0 | 5.2 | 5.3 | 5.5 |
| Augmentation | 2.9 | 2.8 | 0.6 | 0.6 | 0.6 |
| Network Renewal | 5.1 | 4.5 | 4.6 | 4.7 | 4.8 |
| System Total | 13.5 | 12.2 | 10.4 | 10.6 | 10.9 |
| Non-System | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 |
| **Total** | **13.8** | **12.5** | **10.7** | **11.0** | **11.2** |
| **Actual/ Forecast** | | | | | |
| Customer Requested | 7.5 | 10.7 | 11.9 | 11.8 | 11.5 |
| Augmentation | 3.3 | 0.6 | 2.1 | 1.5 | 8.2 |
| Network Renewal | 2.4 | 4.2 | 4.2 | 3.9 | 5.3 |
| System Total | 13.2 | 15.5 | 18.2 | 17.2 | 25.0 |
| Non-System | 0.6 | 0.6 | 2.2 | 2.7 | 2.8 |
| **Total** | **13.8** | **16.1** | **20.4** | **19.9** | **27.8** |
| **Variance** | | | | | |
| Customer Requested | 2.0 | 5.7 | 6.7 | 6.5 | 6.0 |
| Augmentation | 0.4 | (2.2) | 1.5 | 0.9 | 7.6 |
| Network Renewal | (2.7) | (0.3) | (0.5) | (0.8) | 0.5 |
| System Total | (0.3) | 3.2 | 7.7 | 6.6 | 14.1 |
| Non-System | 0.3 | 0.3 | 1.9 | 2.4 | 2.5 |
| **Total Variance** | **0.0** | **3.5** | **9.6** | **9.0** | **16.6** |

Numbers may not add due to rounding.

### 4.4.3 Forecast of Capital Expenditure from 2006/07 to 2010/11

To ensure the ongoing viability of its network, Allgas will continue to actively grow the network through greenfields expansion to new estates. This is reflected in Allgas' capital expenditure program for customer requested works going forward.

In addition, to achieve load growth and reduce costs to end users, new customers must be added to the network, which can only be achieved by encouraging customers to connect high volume and high demand appliances. At present, certain appliances cannot be utilised due to capacity constraints in the network. The replacement of mains to enable higher pressure operation is therefore necessary to enable increases in customer demand, and address current and medium term operating risks associated with older gas pipelines. This is reflected in Allgas' renewal and augmentation program.

As discussed, Allgas has embarked on the upgrade at Ellen Grove Gate Station as part of its South Coast augmentation project. Allgas expects that the pipeline from Ellen Grove to Browns Plains will be completed within 2005/06 resulting in a substantive spike in augmentation for that year. Other significant stages are expected to be completed in 2008/09 with the construction of the 10.2km pipeline from Browns Plains to Logan Reserve and, in 2009/10, a further extension of 12.9km from Logan Reserve to Yatala. This will increase capacity of the network to the South Coast and is expected to support customer demand up to winter 2014.

In the development of its renewals program, Allgas will continue to target minimising UAG and maintenance costs.

Allgas has also included non-system capital expenditure on the basis of recovering the substantial IT, and customer support systems required to enable the business to comply with a range of new network safety, security and market operation requirements that have been enacted in Queensland.

**Table 4.6: Forecast Capital Expenditure ($m Nominal)**

| Year ending 30 June | 06/07 | 07/08 | 08/09 | 09/10 | 10/11 |
|---|---|---|---|---|---|
| Customer Requested | 12.81 | 14.10 | 15.56 | 16.82 | 19.40 |
| Augmentation | 1.49 | 2.46 | 2.94 | 5.54 | 0.09 |
| Network Renewal | 6.52 | 6.51 | 6.59 | 6.66 | 6.73 |
| System Total | 20.82 | 23.07 | 25.09 | 29.02 | 26.22 |
| Non-System | 6.90 | 2.98 | 3.06 | 3.15 | 3.23 |
| **Total Capital Expenditure** | **27.72** | **26.05** | **28.15** | **32.17** | **29.45** |

Numbers may not add due to rounding.

## 4.5 Capital Redundancies

*8.27A Reference Tariff Policy may include (and the Relevant Regulator may require that it include) a mechanism that will, with effect from the commencement of the next Access Arrangement Period, remove an amount from the Capital Base (Redundant Capital) for a Covered Pipeline so as to:*

*(a) ensure that assets which cease to contribute in anyway to the delivery of Services are not reflected in the Capital Base; and*

*(b) share costs associated with a decline in the volume of sales of Services between the Service Provider and Users.*

*Before approving a Reference Tariff which includes such a mechanism, the Relevant Regulator must take into account the uncertainty such a mechanism would cause and the effect that uncertainty would have on the Service Provider, Users and Prospective Users. If a Reference Tariff does include such a mechanism, the determination of the Rate of Return (under sections 8.30 and 8.31) and the economic life of the assets (under section 8.33) should take account of the resulting risk (and cost) to the Service Provider of a fall in the revenue received from sales of Services or part of the Covered Pipeline.*

Table 4.7 outlines Allgas' capital redundancies to 2005/06. Capital redundancies on the Allgas Network occur as a result of pipelines no longer being utilised. This does not include mains replaced as a consequence of pipeline relocations for Local Governments or government departments such as the Queensland Department of Main Roads or the Department of Natural Resources and Mines. The cost of these works is recovered from the individual entities.

The value of the redundant assets has been derived using the asset cost, asset life and remaining life of the redundant assets from the previous Access Arrangement, depreciated to derive a final redundancy value.

**Table 4.7: Past Capital Redundancies ($'000k Nominal)**

| | 01/02 | 02/03 | 03/04 | 04/05 | 05/06 |
|---|---|---|---|---|---|
| **Total** | **40** | **30** | **40** | **30** | **30** |

Numbers may not add due to rounding.

## 4.6 Disposal of Assets

Over the regulatory period, Allgas disposed of assets totalling $3.8 million. The most significant disposal of assets was in 2003/04 when Allgas sold properties at Woolloongabba and Mansfield for a total value of $2.8 million. The remaining disposals were minor non-system assets such as motor vehicles and IT that Allgas sold to ENERGEX Limited over the period. There were no disposals of system assets.

**Table 4.8: Past Disposal of Assets ($m Nominal)**

| | 01/02 | 02/03 | 03/04 | 04/05 | 05/06 |
|---|---|---|---|---|---|
| System Assets | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Non-system Assets | 0.0 | 0.3 | 3.1 | 0.3 | 0.1 |
| **Total Assets** | **0.0** | **0.3** | **3.1** | **0.3** | **0.1** |

## 4.7 Rolling forward the Regulatory Capital Base

Consistent with section 8.9 of the Code, Allgas has rolled forward the capital base as follows:

Regulatory capital base = Initial capital base
- depreciation - redundant capital - asset disposals
+ new facilities investments
+ asset revaluation

To arrive at the opening capital value for this Access Arrangement, Allgas has modified the roll forward applied in the previous Access Arrangement to take account of the actual figures for:

- capital expenditure;
- redundant capital;
- asset disposals; and
- CPI for the purpose of the asset revaluation.

The roll forward of the asset base, determined at the commencement of the previous Access Arrangement, forecast an asset base to apply from 1 July 2006 of $265.0 million.

Table 4.9 shows that after applying the actual values for capital expenditure, asset disposals, redundant capital and inflation for the regulatory period, the opening asset value for 2006/07 equates to $303.2 million. This represents a 14% increase. The difference is predominantly driven by the substantially higher capital expenditure ($98 million compared with $59.2 million) for the period 2001/02 to 2005/06.

**Table 4.9: Proposed Roll Forward of Asset Base – 2001/02 to 2005/06 ($m Nominal)**

| | 01/02 | 02/03 | 03/04 | 04/05 | 05/06 |
|---|---|---|---|---|---|
| Opening Assets | 202.6 | 217.6 | 234.3 | 252.4 | 273.2 |
| Depreciation | (4.7) | (5.1) | (5.2) | (5.3) | (5.6) |
| Disposals | (0.04) | (0.33) | (3.14) | (0. 33) | (0.13) |
| Revaluation | 5.9 | 6.1 | 6.0 | 6.5 | 8.0 |
| Capex | 13.8 | 16.1 | 20.4 | 19.9 | 27.8 |
| **Closing Assets** | **217.6** | **234.3** | **252.4** | **273.2** | **303.2** |

Disposals include capital redundancies. Numbers may not add due to rounding.

Asset appreciation is also higher over the period reflecting the higher capital expenditure and higher than forecast inflation.

**Table 4.10: Asset Inflation Rates (%)**

| All groups, Eight Capitals | 01/02 | 02/03 | 03/04 | 04/05 | 05/06 |
|---|---|---|---|---|---|
| CPI forecast (QCA 2001) | 2.50 | 2.50 | 2.50 | 2.50 | 2.50 |
| Actual CPI | 2.84 | 2.69 | 2.48 | 2.49 | 2.77 |

Source: ABS (Cat No.6401.0)

Having recalculated the opening value of the Allgas regulated asset base as at 1 July 2006, Allgas has applied its forecast capital expenditure, depreciation and asset inflation to determine the asset roll forward for the new Access Arrangement. This is shown in Table 4.11.

**Table 4.11: Forecast Roll Forward of Asset Base – 2006/07 to 2010/11 ($m Nominal)**

| | 06/07 | 07/08 | 08/09 | 09/10 | 10/11 |
|---|---|---|---|---|---|
| Opening Assets | 303.2 | 331.6 | 357.7 | 385.7 | 417.7 |
| Depreciation | (8.1) | (9.5) | (10.4) | (11.4) | (11.9) |
| Disposals | (-) | (-) | (-) | (-) | (-) |
| Revaluation | 8.8 | 9.5 | 10.3 | 11.1 | 12.0 |
| Capex[1] | 27.7 | 26.1 | 28.2 | 32.2 | 29.5 |
| **Closing Assets** | **331.6** | **357.7** | **385.7** | **417.7** | **447.2** |

# 5 RATE OF RETURN

## 5.1 Code Requirements

8.30 *The Rate of Return used in determining a Reference Tariff should provide a return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the Reference Service (as reflected in the terms and conditions on which the Reference Service is offered and any other risk associated with delivering the Reference Service).*

8.31 *By way of example, the Rate of Return may be set on the basis of a weighted average of the return applicable to each source of funds (equity, debt and any other relevant source of funds). Such returns may be determined on the basis of a well accepted financial model, such as the Capital Asset Pricing Model. In general, the weighted average of the return on funds should be calculated by reference to a financing structure that reflects standard industry structures for a going concern and best practice. However, other approaches may be adopted where the Relevant Regulator is satisfied that to do so would be consistent with the objectives contained in section 8.1.*

## 5.2 Rate of Return Applied

Allgas has applied a post-tax nominal WACC of 8.75% to the rolled forward asset valuation.

Allgas engaged Professor Stephen Gray to provide an independent expert report, *The Weighted Average Cost of Capital, Allgas Access Arrangement Revision 2006/07 to 2010/11*, on the appropriate input variables into the WACC calculation. Details of the approach and input assumptions recommended by Professor Gray and adopted by Allgas are summarised below.

## 5.3 Approach to WACC Determination

In determining the return on capital, Allgas has applied a vanilla post-tax nominal WACC (and appropriately defined cash flows). The WACC has been constructed applying the capital asset pricing model (CAPM) to estimate the cost of equity, the use of a debt margin to compute the cost of debt, and the QCA approach for de-levering and re-levering asset and equity betas.[2]

The post-tax nominal WACC is therefore calculated as:

$$\text{WACC} = \text{Ke}\,\frac{E}{V} + \text{Kd}\,\frac{D}{V}$$

where:

Ke = Cost of equity

Kd = Cost of debt

E = Benchmark level of equity

D = Benchmark level of debt

V = Benchmark capital structure

2 Approach adopted by the QCA, the relevant jurisdictional regulator, most recently in (2005) *Final Determination – Regulation of Electricity Distribution.*

## 5.4 Cost of Equity (Ke)

The return on equity (or cost of equity) is the return that investors require for the level of risk associated with their investment. Currently, the most commonly used approach for measuring the required return to equity holders is the Capital Asset Pricing Model (CAPM). This approach has been consistently used in other regulatory decisions throughout Australia.

Allgas has applied a nominal post-tax cost of equity of 11.86% based on the CAPM formula stated as:

Ke = Rf + Be*(MRP)

where:

Ke = Cost of equity/ return that equity holders require

Rf = Risk free rate of return

MRP = Market risk premium

Be = Equity Beta

Each of the inputs to the CAPM formula is discussed below.

### 5.4.1 Risk Free Rate (Rf)

The risk free rate is the rate that an investor would receive from an investment with no or virtually no risk. Commonwealth bonds have long been considered by corporate finance practitioners as an appropriate estimate of the risk free rate.

Allgas has adopted the yield on a Commonwealth Treasury bond with a term to maturity of 10 years on the basis that:

- investment in infrastructure assets is of a long term nature, in which case a risk free asset with similar duration should be used;
- to date, measurement of the market risk premium has largely been based on the 10 year nominal Commonwealth bond; and
- 10 year bonds are less volatile due to their longer-term outlook.

Allgas has used the average yield over the 20 trading days up to and including 24 February 2006 to ensure that the rate not only reflects recent market prices but also eliminates the possibility that short-term volatility may contaminate the data.

This approach provides for an effective annual rate of 5.25%.

### 5.4.2 Market Risk Premium (MRP)

The market risk premium represents the additional return over the risk free rate that an investor would require as compensation for the risks of investing in a well-diversified equity portfolio.

Historical data indicates that up to the end of 2004, the MRP was consistently in excess of 6.0%.

Although the historical data points to a MRP above 6%, there is a degree of academic debate about the length of period that should be used and the extent of the data series to provide the best estimate of the MRP. This data is provided in Table 5.1.

**Table 5.1: Historic Market Risk Premium**

| Length of Period | Period | Mean MRP % |
|---|---|---|
| 30 | 1975-2004 | 7.70 |
| 50 | 1955-2004 | 6.43 |
| 75 | 1930-2004 | 6.58 |
| 100 | 1905-2004 | 7.15 |
| 100 | 1885-2004 | 7.17 |

With this in mind, Allgas considers that there are benefits in adopting a MRP that is uncontentious and well accepted by both regulators and stakeholders. In this regard, Allgas has adopted a MRP of 6.0%, which is consistent with regulatory precedent.

### 5.4.3 Equity Beta (Be)

The equity beta represents the sensitivity of an asset to changes in the value of the market portfolio. The equity beta therefore measures systematic or market risk reflecting variations in earnings or cash flows in line with movements in overall market or macroeconomic factors. These are risks that cannot be eliminated through diversification.

In its 2001 decision on gas distribution, the QCA considered that the appropriate equity beta for an average gas distribution business should be higher than for an electricity distribution business. The QCA determined an equity beta of 0.71 for electricity distribution businesses and 0.97 for gas distribution businesses.

In its 2005 Decision on electricity distribution, the QCA accepted an estimate of 1.0 for the average Australian electricity distribution business. However, it subsequently applied a beta of 0.90 on the basis that its form of regulation reduced systematic risk. The QCA's and other recent regulatory decisions on equity betas are provided below.

**Table 5.2: Recent Regulatory Decisions on Equity Beta**

| Regulator | Industry | Equity Beta |
|---|---|---|
| ACCC (2003) | Gas Transmission | 1.00 |
| ESC (2002) | Gas Distribution | 1.00 |
| ACCC (2002) | Gas Transmission | 0.98 |
| ACCC (2001) | Gas Transmission | 1.16 |
| QCA (2001) | Gas Distribution | 0.97 |
| OFFGAR (2000) | Gas Distribution | 1.08 (midpoint) |
| IPART (2000) | Gas Distribution | 1.00 |
| IPART (1999) | Gas Distribution | 1.03 (midpoint) |
| IPART (1999) | Gas Distribution | 1.00 (midpoint) |
| QCA (2005) | Electricity Distribution | 1.00 avg (specific 0.90) |
| ESCOSA (2005) | Electricity Distribution | 0.90 |
| IPART (2004) | Electricity Distribution | 0.95 (midpoint) |
| ICRC (2004) | Electricity Distribution | 0.90 |
| OTTER (2003) | Electricity Distribution | 0.95 |
| QCA (2001) | Electricity Distribution | 0.71 |
| ESC (2000) | Electricity Distribution | 1.00 |
| SA Govt (1999) | Electricity Distribution | 1.02 (midpoint) |

Given that the equity beta for electricity distribution increased by 27 per cent from 2001 to 2005, and accepting the QCA's 2001 position that the equity beta for a gas distribution business should be higher, gas distribution should also expect an increase in its equity beta. In this regard, applying the 27 per cent increase experienced in electricity distribution equity betas to gas thereby retaining relativity would provide for an equity beta in the vicinity of 1.20.

A higher beta for gas distribution is further supported by the additional risks faced by a gas distribution business over an electricity distribution business, including:

- higher volatility in demand;
- competition from substitute products such as electricity and LPG;
- high unit costs for gas distribution;
- government benefits provided by the Queensland Government to substitute products (eg subsidies for solar hot water and electrical heat pumps); and
- little or no market development from the retail sector.

On balance, adopting the position that a gas distribution business has a higher systematic risk than electricity distribution and observing recent regulatory decisions, Allgas has adopted an equity beta of 1.10.

## 5.5 Cost of Debt (Kd)

The cost of debt is derived using the risk free rate plus a premium for borrowing costs and is derived by:

$$Kd = Rf + Dp + Di$$

Where:

Kd = Cost of debt

Rf = Risk free rate

Dp = Debt premium

Di = Debt issuance cost.

Allgas has a cost of debt of 6.55% based on the parameters described below.

### 5.5.1 Risk Free Rate (Rf)

As discussed in section 5.4.1, Allgas has adopted the yield on a Commonwealth Treasury bond with a term to maturity of 10 years. This approach provides for an effective annual rate of 5.25%.

### 5.5.2 Debt Premium (Dp)

The debt premium reflects the margin over the risk free rate given the credit rating and assumed gearing of the business.

Recent regulatory precedent is to use a credit rating of BBB to BBB+ for a regulated energy distribution business with 60 per cent gearing.

As the debt premium is related to a business's credit rating, the next step is to determine the yield on long term BBB rated corporate bonds relative to the risk free rate.

Allgas has accepted the QCA's recommendation to set the cost of debt at 130 basis points above the risk free rate of return.

#### 5.5.3 Debt Issuance (Di)

In its recent decision on electricity distribution, the QCA allowed for an adjustment to the cost of debt to reflect additional debt financing costs such as establishment and transaction costs including dealer placement, legal, accounting and risk management fees.

Consistent with the QCA's decision on electricity distribution, Allgas has adopted a debt issuance rate of 0.125 per cent.

### 5.6 Capital Structure

In terms of capital structure, Allgas' actual capital structure is not used in the WACC calculation, rather, the level adopted is the "optimal" level of gearing for an efficiently financed benchmarked business.

It is widely regarded among Australian regulators that the appropriate level of gearing to be assumed for any energy distribution business is 60 per cent. Allgas has adopted this benchmark, given that the credit rating, debt margin and equity betas are determined in a way that is consistent with this assumption.

### 5.7 Tax

Tax is not an explicit parameter in the calculation of WACC, rather, it is a component of the cash flows. Its treatment is dependent on the respective tax and imputation rates.

#### 5.7.1 Imputation Rate (y)

The value that the average investor attributes to each dollar of franking credits received is referred to as 'gamma' or the imputation rate.

Under Australia's imputation system, domestic equity investors receive a franking credit that is attached to any dividends paid out of after-tax company profits. This franking credit may be used to offset the personal tax of the investor, and therefore represents additional cash flow to the investor.

Allgas has accepted the QCA's recommendation of a gamma of 0.50.

### 5.8 Inflation (CPI)

Expected inflation is not an explicit parameter in the calculation of WACC but is a component of the risk free rate.

Consistent with regulatory precedent, Allgas has adopted an expected inflation rate based on the difference between the 10 year Commonwealth bond rate and a similar indexed bond rate over 20 days commencing 8 August June 2005. The 20 trading day average yield on a Commonwealth indexed Bond was 2.41 per cent, while on the Commonwealth bond the rate was 5.18 per cent.

Allgas has adopted an expected inflation rate of 2.77 per cent.

## 5.9 Calculating the WACC

The input parameters and the subsequent WACC applied by Allgas are provided in the following table.

**Table 5.3: Summary of WACC parameters**

| Parameter | Result |
|---|---|
| Risk Free Rate | 5.25% |
| Market Risk Premium | 6.00% |
| Debt Margin | 1.30% |
| Debt Financing Cost | 0.125% |
| Credit Rating | BBB/BBB+ |
| Equity Beta | 1.10 |
| Gamma | 0.50 |
| Debt/Equity | 60% |
| Inflation | 2.77% |
| Cost of Equity | 11.86% |
| Cost of Debt | 6.55% |
| **WACC (post-tax nominal)** | **8.75%** |

# 6 NON-CAPITAL COSTS

## 6.1 Approach

Forecasts of non-capital costs have been developed by Allgas for the five years of the Access Arrangement to 2010/11. Allgas has included significant operating efficiency savings which it expects to realise over the forecast period. These forecasts are described below.

The categories of cost specified within the forecast include:

- **Inspections** –- includes costs related to the recurring process of inspecting Allgas distribution network. For example, inspections are carried out with respect to leak surveys on mains and services, regulators and sleeves;
- **Planned Maintenance** –- includes costs associated with the ongoing maintenance and repair of assets. Planned maintenance also includes preventative maintenance, which is undertaken to prevent failure by providing systematic detection and prevention of failure. Allgas' preventive maintenance is conducted according to a planned maintenance program;
- **Corrective Maintenance** –- includes costs associated with maintenance which is required when assets fail and are to be brought back into working order. For example, corrective maintenance includes costs associated with cased crossings;
- **Customer Service** –- is related predominately to meter reading services, market operation and also includes costs associated with customer network enquiries;
- **Maintenance Planning and Support** –- includes licence fees and costs associated with *Petroleum and Gas (Production and Safety) Act 2004* and the *Gas Supply Act 2003*, developing the maintenance program, compliance reporting to Regulators and costs associated with the meter measurement scheme;
- **Network Development** – includes costs to cover activities such as liaising with developers, promoting the safe use of gas and gas appliances, satisfying environmental requirements and promoting additional gas usage and network utilisation through public awareness; and
- **Ancillary Services** – includes the costs to cover Special Meter Reads, Reconnection and Disconnection Services.

## 6.2 Total Costs

Forecast operating and maintenance costs for the five years to 30 June 2011 are summarised in Table 6.1. These costs include the impact of consumption growth over the period, and hence show real reductions in operating and maintenance costs.

**Table 6.1: Forecast Non-Capital Costs (excluding UAG) ($m Nominal)**

| Year Ending 30 June | 06/07 | 07/08 | 08/09 | 09/10 | 10/11 |
|---|---|---|---|---|---|
| Inspection | 1.29 | 1.73 | 1.73 | 1.83 | 1.72 |
| Planned Maintenance | 3.04 | 3.03 | 3.00 | 2.67 | 2.82 |
| Corrective Maintenance | 2.52 | 2.46 | 2.34 | 2.03 | 1.87 |
| Customer Service | 0.99 | 0.99 | 1.08 | 1.17 | 1.25 |
| Maintenance Planning & Support | 2.48 | 2.27 | 2.35 | 2.33 | 2.32 |
| Network Development | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 |
| Ancillary Service Costs | 0.60 | 0.59 | 0.68 | 0.78 | 0.77 |
| **Total Non-Capital Costs (excluding UAG)** | **11.52** | **11.67** | **11.78** | **11.41** | **11.35** |

Numbers may not add due to rounding.

The operations of Allgas in regard to the Access Arrangement are the subject of agreements between Allgas and ENERGEX Limited. ENERGEX Limited is engaged as an independent contractor to operate and manage the Natural Gas Network and provide most support services. As a result, Allgas does not incur operations and maintenance expenditure on wages and salaries, rental equipment, materials and property taxes. As all operations and maintenance costs are incurred by ENERGEX Limited, the total Non-Capital costs shown in Table 6.1 represents costs of services provided by others.

Network development services are also performed by ENERGEX Limited under the above agreements. This activity involves the active promotion of gas reticulation into new residential developments.

Fees are now paid directly by Allgas to the Queensland Government for Distribution Authorities and for the regulation of gas safety and standards. These fees were previously charged on the level of retail sales and were excluded from regulated Non-Capital cost in the Allgas Access Arrangement 2001. These fees are now included in regulated costs.

## 6.3 Efficiency of Non-Capital Costs

While there exists a multitude of economic techniques available to assess cost efficiency, given the relatively few gas distribution businesses operating in Australia there are generally insufficient observations available to support most techniques.

Furthermore, operating environment conditions also have a significant impact on distribution costs and productivity and in many cases can be beyond the control of management. Consequently, when assessing the comparative efficiency of gas distribution businesses it is necessary to normalise comparisons to account for the most important operating differences. As a result, the measure of productivity improvements can be difficult. While this does not imply that continuous efficiency gains cannot be achieved, it suggests that caution should be exercised when expected efficiency gains are derived through comparative analysis.

Allgas notes that recent regulatory decisions on gas distribution have considered productivity improvements in the range of 1.5% to 2.5% reasonable for the gas industry. Notwithstanding the issues identified with respect to benchmarking, Allgas considers this range a sensible target for continuous improvement.

Allgas considers that the main driver that impacts on its Non-Capital costs are the length of the distribution network. Accordingly, Allgas has adopted a growth rate that reflects this component for assessing its Non-Capital cost forecasts. Allgas has also used an escalation factor of 0.50.

Allgas has assessed the efficiency of its forecast Non-Capital costs (excluding Network Development and Ancillary Service costs) over the term of the Access Arrangement. As indicated in Table 6.2, Allgas has implied efficiency gains of over 4.0% on average over the period.

**Table 6.2: Forecast Implied Efficiency Gains**

| | 06/07 | 07/08 | 08/09 | 09/10 | 10/11 |
|---|---|---|---|---|---|
| Operating Costs ($m) | 10.9 | 10.8 | 10.7 | 10.4 | 10.4 |
| C = Annual Change | | -0.9% | -0.8% | -3.0% | -0.2% |
| Growth in mains | 4.2% | 4.6% | 4.4% | 4.6% | 4.6% |
| G = mains growth * 0.5 | 2.1% | 2.3% | 2.2% | 2.3% | 2.3% |
| CPI | 2.8% | 2.8% | 2.8% | 2.8% | 2.8% |
| **X = CPI + G - C** | | **4.2%** | **4.2%** | **2.1%** | **4.9%** |

## 6.4 Regulated and Unregulated Costs

In determining operating and maintenance costs, costs were allocated between regulated and unregulated segments. Because various activities are ring-fenced, a large percentage of the operations and maintenance costs were directly attributable to the regulated business. Where costs were required to be apportioned, cost drivers based on the activities concerned were applied.

Allgas' unregulated business is restricted to a single point to point pipeline supplying one gas customer.

## 6.5 Unaccounted for Gas (UAG)

The QCA allowed Allgas to recover $7.5 million for Unaccounted for Gas (UAG) over the current regulatory period.

Allgas contends that reducing UAG is not the objective, rather it is the result of a combination of ensuring minimum safety requirements are met and the extent of allowed refurbishment of the network.

Over the regulatory period Allgas has exceeded augmentation expenditure allowed by the QCA. Allgas has also undertaken extensive renewals projects replacing significant amounts of aged cast iron pipes in Hawthorn, Kangaroo Point, East Brisbane and South Brisbane. Allgas is also progressing with its renewals program in West End, due for completion in late 2005.

As a result of these projects, Allgas has been able to close the gap between its performance at the outset of the regulatory regime and the benchmarks established by the QCA.

### 6.5.1 Description and Forecast

UAG occurs due to a combination of leakage in pipes, Metering errors and accounting errors created by timing differences in meter readings, and variable linepack and purging.

All things being equal, there is an inverse correlation between UAG and network refurbishment.

The Allgas Network has a significant proportion of older cast-iron mains and accordingly leaks do occur. While it is recognised that leakage of gas is not desirable, Allgas cannot immediately justify the large capital expenditure that would be required to remove all cast-iron mains from service throughout the Network. Upgrade works to reduce UAG are driven by several factors. First, any leak that constitutes a safety concern must be repaired in accordance with relevant legislation. Repair or replacement of the relevant sections is always carried out in these instances. Secondly, for minor leaks that do not result in safety concerns, Allgas adopts the approach of targeting UAG levels that are economically efficient. If UAG increases substantially and the cost of lost gas begins to exceed the cost of repair or replacement, work is carried out to reduce the leakages.

Thirdly, if the cost of ongoing repairs is excessive, then Allgas will carry out insertion or mains replacement to remove the offending mains. However, whether to continue to repair mains or replace sections of mains is an issue that is determined based on commercial economic criteria. Allgas has a mains replacement program in place and this is aimed at optimisation of outcomes for End Users, while maintaining the necessary safety standards. This mains replacement program results in the reduction of UAG costs over the term of the Access Arrangement as shown in Table 6.3. The implementation of this program is subject to commercial justification of each individual stage.

As discussed, Allgas' renewal program will produce significant savings to consumers over the regulatory period through lower UAG costs. This will be achieved even though system use gas has to be firm (non-interruptible).

**Table 6.3: Forecast Costs of UAG ($m Nominal)**

| | 06/07 | 07/08 | 08/09 | 09/10 | 10/11 |
|---|---|---|---|---|---|
| **Cost of UAG** | **1.5** | **1.4** | **1.4** | **1.3** | **1.2** |

## 6.6 Forecast Tax

While tax is not considered an operating cost, when incurred it is nevertheless a cost to the business. It is not included in Allgas' Non-Capital cost forecast but Allgas has separately identified it for its inclusion in the cash flows within the Cost of Service model. This is consistent with the post-tax nominal framework in this Access Arrangement.

Allgas' tax forecast for the Access Arrangement period based on the building block forecasts and a Regulatory tax derived using the imputation rate of 0.50 (see section 5.7.1) is detailed in Table 6.4.

**Table 6.4: Allgas Tax Forecast to 2010/11 ($m Nominal)**

| | 06/07 | 07/08 | 08/09 | 09/10 | 10/11 |
|---|---|---|---|---|---|
| Tax Payable | 2.8 | 2.7 | 2.8 | 3.2 | 3.5 |
| **Regulatory Tax** | **1.4** | **1.3** | **1.4** | **1.6** | **1.8** |

# 7 TOTAL REVENUE

## 7.1 Code Requirements

8.4 *The Total Revenue (a portion of which will be recovered from sales of Reference Services) should be calculated according to one of the following methodologies:*

***Cost of Service:*** *The Total Revenue is equal to the cost of providing all Services (some of which may be the forecast of such costs), and with this cost to be calculated on the basis of:*

*(a) a return (**Rate of Return**) on the value of the capital assets that form the Covered Pipeline or are otherwise used to provide Services (**Capital Base**);*

*(b) depreciation of the Capital Base (**Depreciation**); and*

*(c) the operating, maintenance and other non-capital costs incurred in providing all Services (**Non-Capital Costs**).*

***IRR:*** *The Total Revenue will provide a forecast Internal Rate of Return (IRR) for the Covered Pipeline that is consistent with the principles in sections 8.30 and 8.31. The IRR should be calculated on the basis of a forecast of all costs to be incurred in providing such Services (including capital costs) during the Access Arrangement Period.*

***NPV:*** *The Total Revenue will provide a forecast Net Present Value (NPV) for the Covered Pipeline equal to zero. The NPV should be calculated on the basis of a forecast of all costs to be incurred in providing such Services (including capital costs) during the Access Arrangement Period, and using a discount rate that would provide the Service Provider with a return consistent with the principles in sections 8.30 and 8.31.*

## 7.2 Overview of the Allgas Approach

The Total Revenue determination for Allgas is essentially a Cost of Service approach and accords with Code requirements. Annual Total Revenues have been determined as shown.

1. **Establish starting capital base**
2. **Establish future costs**
   - Non-Capital cost including UAG
   - Depreciation
   - Tax Payable
   - Capital expenditure
3. **Establish the base and future year revenues**

| | | |
|---|---|---|
| Base Revenue | = | WACC * Capital Base – Revaluation + Depreciation + Non-Capital costs + UAG + Tax payable – Franking credits |
| Capital base | = | Capital Base Previous Period + 0.5* Capital Expenditure; and |
| Revaluation | = | CPI *Capital base. |

**4. Apply revenue smoothing**

## 7.3 Total Revenue Summary

Total Revenues for the five year period are summarised in Table 7.1.

**Table 7.1: Revenue Summary ($m Nominal)**

| Year ending 30 June | 06/07 | 07/08 | 08/09 | 09/10 | 10/11 |
|---|---|---|---|---|---|
| Return on assets | 27.7 | 30.2 | 32.5 | 35.2 | 37.8 |
| Capital Appreciation | (8.8) | (9.5) | (10.3) | (11.1) | (12.0) |
| Depreciation | 8.1 | 9.5 | 10.4 | 11.4 | 11.9 |
| Non-Capital costs | 11.7 | 11.8 | 11.9 | 11.6 | 11.5 |
| Unaccounted for gas | 1.5 | 1.4 | 1.4 | 1.3 | 1.2 |
| Regulatory Tax | 1.4 | 1.3 | 1.4 | 1.6 | 1.8 |
| **Total Revenue** | **41.7** | **44.7** | **47.4** | **49.8** | **52.3** |

Numbers may not add due to rounding.

### 7.4 Revenue Adjustments

In order to determine the annual revenues to be used to calculate Reference Tariffs, the following adjustments may be applied to the Total Revenue numbers in Table 7.1:

- an adjustment to account for the forecast revenue from Ancillary Services; and
- an adjustment to account for forecast Capital Contributions.

### 7.4.1 Ancillary Services

Allgas provides Ancillary Services such as: Special Meter Reads; Inlet Disconnections; and Inlet Reconnections. The annual charges for these services are shown in Appendix B of the Allgas Access Arrangement and the costs are included within Allgas' Non-Capital cost forecasts in section 6.

**Table 7.2: Forecast Revenue from Ancillary Services ($m Nominal)**

| | 06/07 | 07/08 | 08/09 | 09/10 | 10/11 |
|---|---|---|---|---|---|
| **Ancillary Services** | **0.6** | **0.6** | **0.7** | **0.8** | **0.8** |

Allgas has deducted the forecast annual revenue from Ancillary Services shown in Table 7.2 from the proposed Total Revenues shown in Table 7.1.

### 7.4.2 Capital Contributions

*8.23 New Facilities Investment may also be added to the Capital Base when a User makes a Capital Contribution (as defined below) in respect of a New Facility. Nothing in this Code prevents a User agreeing to pay the Service Provider a Charge which exceeds the Charge that would apply under a Reference Tariff for a Reference Service (or, in relation to another Service, under the Equivalent Tariff) in any circumstance including, without limitation, if the excess is paid in respect of the funding of a New Facility (in which case the extra payment is a Capital Contribution).*

Allgas seek capital contributions from customers connecting to its distribution network when the expected future earnings from these customers' network charges are not expected to recover the full cost of servicing the customer. Allgas recognises that a certain proportion of its revenue will come from capital contributions made by customers for connection assets.

Table 7.3 shows the average capital contributions received over the previous regulatory period and the forecast level of annual capital contributions out to 2010/11. As shown, Allgas only requires a small quantity of capital contributions.

**Table 7.3: Actual and Forecast Capital Contributions ($m Nominal)**

| | 2001-2006 | 06/07 | 07/08 | 08/09 | 09/10 | 10/11 |
|---|---|---|---|---|---|---|
| Capital Contributions | 0.2 p.a. | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |

Allgas has deducted from its proposed Total Revenue shown in Table 7.1 the forecast capital contributions over the next Access Arrangement as well as adjusting for the capital contributions over the current access period.

Allgas has also deducted its capital contributions from the current access period from its total revenue forecasts. The $1.2 million adjustment for capital contributions received in this period has been made to Allgas' future total revenue requirements to 2010/11.

## 7.5 Smoothing

It is desirable to smooth the revenue over the Access Arrangement period to ensure that prices can be similarly transitioned over the period. Allgas has smoothed using a Net Present Value (NPV) approach.

# 8 COST ALLOCATION METHODOLOGY

## 8.1 Code Requirements

*8.1 The service provider's reference tariff and reference tariff policy should be designed with a view to achieving the following objectives:*

*(a) providing the Service Provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the Reference Service over the expected life of the assets used in delivering that Service;*

*(b) replicating the outcome of a competitive market;*

*(c) ensuring the safe and reliable operation of the Pipeline;*

*(d) not distorting investment decisions in Pipeline transportation systems or in upstream and downstream industries;*

*(e) efficiency in the level and structure of the Reference Tariff; and*

*(f) providing an incentive to the Service Provider to reduce costs and to develop the market for Reference and other Services.*

*To the extent that any of these objectives conflict in their application with a particular Reference Tariff determination, the Relevant Regulator may determine the manner in which they can be reconciled or whether a particular objective should prevail.*

*8.2 Factors about which the regulator must be satisfied in determining to approve a reference tariff and reference tariff policy are that:*

*(a) the revenue to be generated from the sales (or forecast sales) of all Services over the Access Arrangement Period (the Total Revenue) should be established consistently with the principles and according to one of the methodologies contained in section 8;*

*(b) to the extent that the Covered Pipeline is used to provide a number of Services, that portion of Total Revenue that a Reference Tariff is designed to recover (which may be based upon forecasts) is calculated consistently with the principles contained in this section 8;*

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

*(d) incentive Mechanisms are incorporated into the Reference Tariff Policy wherever the Relevant Regulator considers appropriate and such Incentive Mechanisms are consistent with the principles contained in this section 9; and*

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

This section seeks to convey the principles underpinning the Allgas cost allocation methodology and illustrate that the Code requirements are satisfied.

## 8.2 Reference Tariff Cost Allocation Principles

The Reference Tariffs are designed to meet the Code's objectives as explained below. The key objectives of the policy include recovering the efficient costs of providing Reference Services, with emphasis on the safety and integrity of the Network, providing price certainty to Users, and signalling appropriate investment in the development of the market.

- **Cost Reflectivity** – The tariffs reflect a recovery of efficient costs associated with delivering the services of the Network. When benchmarking these costs against other providers, Allgas' costs are relatively low. Built into the forecasts are efficiency gains and these will pass directly to Users within the regulatory review period.
- **Efficient Pricing Signals** – The revenues associated with the Reference Tariffs reflect economically efficient pricing principles. That is, the revenues for each of the Reference Tariffs have been set so that they are between incremental and stand-alone cost benchmarks. If revenue falls below the incremental cost of supply for an End User the incentive for Allgas to connect similar Prospective End users is removed. If revenue per End User exceeds the stand-alone costs of replicating the Reference Service there is a risk of bypass resulting in inefficient use of resources. Thus the Reference Tariffs have been structured so that resources are allocated efficiently.

  In addition, if revenues from a group of End Users that are located within a discrete network exceed the stand-alone costs of replicating the Reference Service then there is a risk of coordinated[3] joint bypass resulting in inefficient use of resources.

  Within each of these Reference Tariffs some re-balancing will be required over a transitional period to ensure that the pricing for individual End Users complies with efficiency criteria.
- **Price Stability** – The reference tariffs have been designed to provide certainty and stability of pricing for all Users. Reference Tariffs have been smoothed over the term of the access arrangement to avoid shocks in any year and provide stability and certainty for End Users.
- **Replicating competitive market outcomes** – The tariffs are designed so that the prices reflect the most efficient use of the distribution system resources. Assets are allocated to each Tariff class according to the relative use by that customer class. Non-Capital costs are allocated to the appropriate assets and then to the Tariff classes. Costs are benchmarked and prices are forecast to deliver real gains in productivity to Users.
- **Safe and reliable operation** – Capital expenditure and Non-Capital cost forecasts are designed to deliver distribution Network safety, reliability and integrity both in terms of design and operation. Users are entitled to the safe use of the distribution system and forecasts are designed to deliver benefits both in terms of reduced unaccounted for gas and reduced operational and maintenance expenditure.
- **Appropriate Investment Decisions** – The Reference Tariffs are modelled so as to provide efficient investment signals for the development and growth of the Network. The Reference Tariff for the Demand Customer Service has been designed to avoid uneconomic duplication of the Network and encourage an efficient use of resources. The fixed and variable components of pricing have been designed to signal the most efficient use of assets and maximise utilisation of the Network which drive lower unit costs for the usage of such assets. This also results in a tariff which represents an efficient Network design to supply that End User.

[3] In assessing the joint bypass risks we have factored in an estimate of the costs associated with coordination.

The pricing approach for the Demand Customer group incorporates the prudent discount approach identified in section 8.43 of the Code. The regulator has approved the application of prudent discounts for particular Demand Customers.

## 8.3 Overview of Cost Allocation Process

Allgas assigned the Total Revenue to the customer service groups using a cost allocation process. This process involves the following main steps:

- determine Total Revenue for each year – refer section 7 above for derivation;
- capital, operating and maintenance costs relating to the Network assets are divided into cost pools based on defined asset groups;
- customer groups (and thus the tariff categories) are defined based on consumption levels, allocated connection infrastructure and location;
- the costs for the End Users from the Demand Customer Service group are deducted based on stand-alone pricing principles; and
- the remaining costs are allocated based on asset usage.

Reference Tariffs are designed to recover the Total Revenue allocated to each customer service group based on the forecast utilisation and customer growth.

This Total Revenue apportionment and cost allocation approach ensures that the revenue derived from the application of the Reference Tariffs (modelled using the forecast load and customer growth) is equal to the Total Revenue should the assumptions regarding costs and demand growth hold.

## 8.4 Customer Groups

The Reference Services derived for application under the Access Arrangement are as follows:

- Volume Customer Service; and
- Demand Customer Service.

These Reference Services were chosen to represent reasonably homogeneous groupings of End Users taking into account the consumption patterns and quantities, the connection and Metering types and End User locality while also considering pricing constraints.

Table 8.1 sets out the customer classes adopted and the definitions of the Reference Services, as defined in the Access Arrangement. Note that the information in Table 8.1 shows the customer class (customer numbers as at 30 June 2005) for calculation of the cost of supply only.

**Table 8.1: Customer Groups**

| Customer Group | Description/Reference Service | Number of Customers |
|---|---|---|
| Volume | The Volume Service is available where the End User is reasonably expected to withdraw a quantity of Natural Gas less than 10TJ per year. This Service provides for the transportation of gas delivered into the Network by or on behalf of the End User. | 64,413 |
| Demand | The Demand Service is available where the End User is reasonably expected to withdraw a quantity of Natural Gas of at least 10TJ per year. This Service provides for the transportation of gas delivered into the Network by or on behalf of the End User. | 111 |

## 8.5 Locational Zones

Allgas has a unique situation in that the transmission pipeline is relatively close to many of its largest End Users and hence physical bypass is a real consideration. Calculations show that using average prices for the Demand Customer Service will result in some End Users receiving prices above stand-alone cost of supply, whereas others will receive prices well below the stand-alone costs. These inefficient pricing outcomes are not desirable for either Allgas or the End Users as Allgas is at risk of physical bypass and the End Users are paying an unacceptably high cost of supply. Allgas has therefore established pricing zones for the Demand Customer Service based on distance from the transmission pipeline:

- Brisbane – 3 Zones;
- Toowoomba – 2 Zones;
- Oakey – 2 Zones; and
- South Coast – 3 Zones.

Maps of the relevant zones are provided in Attachment 1. The primary considerations adopted by Allgas in the establishment of these zones included:

- simplicity – providing a price that can be readily understood by all Users;
- cost reflectivity – maximising the linkage between Network prices and the cost of supplying individual End Users that qualify for the Demand Customer Service;
- deterring uneconomic bypass; and
- minimisation of boundary conditions.

The pricing zone Reference Tariffs for the Demand Customer Service were developed using a number of stand-alone Networks. These stand alone Networks were used to calculate the portion of the allocated costs attributable to the Demand Customer Service group in a particular supply area. This process involved:

- identifying the location of each End User within the Demand Customer Service with respect to the transmission pipeline;
- identifying the costs of an efficient stand-alone Network to supply End Users from the transmission pipeline. This involved the grouping of End Users to provide efficient infrastructure to that group of End Users; and
- computing the required revenue for each End User resulting from this efficient stand-alone Network.

## 8.6 Revenue Allocation

The revenue allocation for the Allgas Network was carried out as follows:

1. To deliver an efficient pricing level for every End User in the Demand Customer Service, a model was used to calculate a cost that was reflective of the optimal assets required to provide the service, including utilisation of shared infrastructure where there are multiple End Users in a region. The revenue requirement for the Demand Customer Service is derived in this way.

2. The costs derived under step 1 are then used to derive the allocation of asset related costs to the Demand Customer Service.

3. The final step in the process is to allocate remaining asset related costs to the Volume Customer Service.

## 8.7 Allocation of Unaccounted For Gas

As discussed in section 6.5, Unaccounted for Gas (UAG) occurs due to a combination of leakage in pipes, Metering errors and accounting errors created by timing differences in Meter readings.

Allgas has allocated the cost of UAG in accordance with the allocation methodology used to determine Reference Tariffs.

## 8.8 Total Revenue Outcome

The Reference Tariffs arising from the cost allocation and tariff structure process were modelled against the forecast consumption and demand parameters and the annual forecast revenue derived. The revenue outcome is reflective of the Total Revenue for 2006/07 as allocated through the methodology described in previous sections. This modelling ensures the Allgas Reference Tariffs are compliant with section 8 of the Code, in that the Reference Tariffs recover from users of that Reference Service an appropriate portion of Total Revenue.

# 9 PRICING STRUCTURES

## 9.1 Introduction

The Reference Tariff design incorporates the following key features:

- daily fixed charges based on the nominal Metering and service facilities;
- $/GJ charges based on the actual gas consumption or nominated MDQ for the period; and
- nominated MHQ charges for the Demand Customer Service.

## 9.2 General Principles

The principles adopted in the development of the Reference Tariff structures for the customer service groups include:

- fixed charges cover a proportion of the Service and Metering costs as well as a percentage of the administration servicing costs;
- nominated MHQ or demand charges reflect the average costs of shared Network provision or contracted capacity;
- $/GJ or $/GJ of MDQ charges are used for the recovery of other costs; and
- $/GJ or $/GJ of MDQ charges are declining block tariffs to provide incentives to improve Network utilisation.

The tariffs ensure that there are no major pricing discontinuities at the boundary between Reference Tariffs. Such discontinuities can provide perverse incentives for End Users to change Reference Services.

## 9.3 Transitional Principles

The Reference Tariffs take account of the following factors:

- avoiding significant price shocks;
- a transition towards full cost reflectivity; and
- the recovery of reasonable revenues to enable Allgas to continue the operation of the Network in a viable manner.

In recognition of these factors, the Reference Tariffs have been set to recover Total Revenue while not causing significant price changes. Over the period of the Access Arrangement, the Reference Tariffs will be adjusted in accordance with the mechanisms described in section 3.3 of the Access Arrangement. This will enable further progression towards full cost reflectivity.

This results in the following revenue targets for each customer class, consistent with the price paths outlined in the Access Arrangement.

**Table 9.1: Forecast Revenue by Customer Class ($m Nominal)**

| | 06/07 | 07/08 | 08/09 | 09/10 | 10/11 |
|---|---|---|---|---|---|
| Demand customer class | 11.8 | 12.4 | 12.9 | 13.3 | 13.7 |
| Volume customer class | 28.8 | 31.2 | 33.3 | 35.3 | 37.3 |
| **Target Revenue** | **40.6** | **43.6** | **46.2** | **48.6** | **51.0** |

# 10 SYSTEM DESCRIPTION

## 10.1 Introduction

The following is a brief description of the Allgas distribution system. The system is separated into four (4) Natural Gas operating regions. These are the “Brisbane Region” (south of the Brisbane River); “Western Region” (encompassing the townships of Toowoomba and Oakey in Queensland); “South Coast Region” including Gold Coast and “Tweed Heads” in north east New South Wales.

Maps of the Network are included in Attachment 2.

## 10.2 Allgas Distribution Network – Brisbane Region

The Allgas gas distribution Network is located south of the Brisbane River starting from Dinmore and Springfield in the west to Cleveland in the east, Marsden and Loganlea in the south and Wynnum in the north. The Network comprises approximately 2,300 km of high pressure, medium pressure and low pressure pipelines. The Network is constructed of steel, polyethylene and cast iron mains.

Natural gas is supplied into the distribution network from the Roma to Brisbane transmission supply pipeline. The transmission pipeline is largely a 300DN steel, Class 600, while the metropolitan portion of the transmission pipeline from Wishart to Doboy operates at a nominal operating pressure of 4,200 kPa and from Ellengrove to Wishart at 4,600 kPa. Gate stations are situated at Ellengrove, Runcorn, Wishart, Tingalpa and Doboy.

The natural gas from the transmission pipeline is metered at the gate stations by turbine Meters with flow computers used to correct for pressure and temperature variations. Odourisation of the gas is also provided at the gate stations.

The older areas of the Network comprising cast iron and steel mains are supplied through subgate or district regulator stations at Ekibin, West End, Wishart, Morningside, Salisbury, Sherwood and Wynnum. The district regulator stations serve as a pressure letdown facility from the high pressure into the medium pressure and low pressure systems. The volume of gas entering the medium and low pressure areas is Metered and used in UAG calculations. These district regulator stations are also used for humidifying and oil fogging of the gas flowing through areas where older pipelines are installed. The purpose of this process is to preserve the integrity of the old cast iron and steel Networks.

The Brisbane distribution Network is divided into high pressure (steel and PE), medium pressure and low pressure systems.

### 10.2.1 High Pressure Steel System

The 210 km high pressure Network is comprised of Class 150 and Class 300 steel pipelines with the operating pressures of the system set at the gate stations. Table 10.1 details the operating pressures of the various high pressure systems. The high pressure steel system is connected to high pressure polyethylene (PE), medium pressure and low pressure systems by approximately 200 district regulating stations.

**Table 10.1: High Pressure System (Steel)**

| Gate Station | Location | Class | MAOP (kPa) | Nominal Operating Pressure (kPa) |
|---|---|---|---|---|
| Dinmore | Riverview Road, Ipswich | 300 | 4200 | 650 |
| Ellengrove | Woogaroo Street | 150<br>300 | 1200<br>4200 | 1000<br>2200 |
| Runcorn | Gowan Road | 150<br>300 | 1200<br>4200 | 1000<br>2350 |
| Mt Gravatt | Greenwood Street | 150 | 1200 | 800 |
| Tingalpa | Stanton Road | 150 | 1200 | 850 |
| Doboy | Lytton Road, Murarrie | 150 | 1200 | 900 |

The Dinmore gate station is owned and operated by Envestra

### 10.2.2 High Pressure Polyethylene System

A high pressure PE system operates in parallel with a high pressure steel system in various parts of Brisbane. The system consists of 250 km of PE mains ranging from 40 mm to 160 mm in size. The 500 kPa MAOP (Maximum Allowable Operating Pressure) system generally operates at 100 to 200 kPa pressures. Geographically, this system operates through Woodridge, Kingston, Carole Park, Forest Lake, Springfield, Loganlea, Eagleby, Algester, Jindalee, Inala, Sunnybank, Mansfield, Manly, Tingalpa, West End, Woolloongabba and other parts of Brisbane.

### 10.2.3 Medium and Low Pressure Systems

The medium and low pressure distribution Network comprises a total of approximately 400 km of pipeline with sizes ranging from 40 mm to 450 mm. Approximately 200 km of the mains are cast iron or steel.

The low pressure Network comprises approximately 375 km of steel and cast iron mains in the older districts of Brisbane and Wynnum. Approximately 160 km of these mains are currently located under roadways due to road widening operations over the last several decades. In addition, the low pressure Network contains approximately 70 km of PE or PVC gas mains.

There are three (3) major medium and low pressure systems in Brisbane.

*Sherwood System*

This system is fed by the Sherwood district regulator station. The system is a medium pressure Network. The MAOP of this medium pressure Network is 35 kPa and the average operating pressure is 15 kPa. The system is comprised of steel, cast iron and PE mains.

*Older Districts*

This system covers the inner city areas of West End, Woolloongabba, Balmoral, Camp Hill, Coorparoo, Holland Park, Moorooka and Yeronga. The system is a complex Network of low and medium pressure mains comprised of steel, cast iron and PE. The average operating pressure is 22 kPa for the medium pressure Network and 1.25 kPa for the low pressure Network.

*Wynnum System*

This low pressure system covers the suburbs of Wynnum, Manly and Lota. The majority of the mains are steel and cast iron and the system operates between 1.3 and 1.6 kPa pressures.

## 10.3 Allgas Distribution Network – Western Region

The 116 square kilometres of the Allgas Western Region Network consists of 96 square kilometres within the Toowoomba area, bordered by the escarpment in the east to Allen Court in the West, Hermitage Road in the North to Nelson Street in the South.

The remaining 20 square kilometres are located within the Jondaryan Shire Council boundaries at Oakey, with the Network extending from Kearneys Road in the West to; Hamlyn Road in the East, Oakey Aviation Base on Orrs Road to the North and Shannan Street to the South.

A 17.8 kilometre spur main from the Oakey Gate Station extends southward to Purrawanda to supply a single industrial End User.

Both Toowoomba and Oakey Gate Stations are supplied with transmission pressure (5500 to 7000 kPa) gas from the Ballera to Roma and Roma to Brisbane pipelines. The Roma to Brisbane pipeline is owned by APT and operated by Agility. The gate station at Oakey is owned and operated by Allgas, whereas the Toowoomba Gate Station is operated by Agility. At Toowoomba Gate Station, the odourisation facilities and final stage stand-by regulator are owned by Allgas.

Natural gas is metered at the gate stations by turbine Meters with flow computers used to correct for pressure and temperature variations.

The Oakey Network is a relatively new system with only three (3) sub-systems and operating pressures:

1. high pressure, steel operating at a nominal pressure of 1000 kPa (MAOP 1050 kPa);
2. high pressure PE Network operating at a nominal pressure of 140 kPa (MAOP 500 kPa); and
3. high Pressure PE Network operating at a nominal pressure of 680 kPa (MAOP) 700 kPa).

The township of Toowoomba is comprised of 1 and 2 above, plus the old converted town gas low pressure Network operating at a nominal pressure of 1.25 kPa. The low pressure mains construction dates from 1880 to the present, and consist of cast iron, UPVC, steel, galvanised malleable steel and PE.

Toowoomba also has a 6.5km class 300 high pressure steel main supplying the Wiboton industrial estate from the gate station.

Within Toowoomba there are a number of sub-Networks with varying operating pressures as described in **Table 10.2**.

**Table 10.2: Toowoomba System**

| High Pressure Steel | High Pressure PE | Low Pressure Wet Gas |
|---|---|---|
| High Pressure Steel<br>OP=1000kPa,MAOP=1050 kPa<br>Class 300<br>OP=1150kPa, MAOP=4200 kPa | Class 500<br>OP = 200 kPa<br>MAOP = 500 kPa | OP = 1.25 kPa<br>MAOP = 2.0 kPa |
| **Medium Pressure** | **Medium Pressure Dry Gas** | **Low Pressure Dry Gas** |
| OP = 17 kPa<br>MAOP = 35 kPa | OP = 7.0 kPa<br>MAOP = 35 kPa | OP = 1.25 kPa<br>MAOP = 2.0 kPa |

### 10.3.1 High Pressure Steel System

The 55 kilometres of high pressure Network is comprised of high pressure steel to AS1697 and Class 300 steel. The maximum operating pressures of the high pressure system are set at the gate stations. The high pressure steel systems supply gas to the high pressure PE, medium and low pressure systems via district regulating stations.

**Table 10.3: High Pressure Steel System**

| Gate Station | Location | Class | MAOP (kPa) | OP (kPa) |
|---|---|---|---|---|
| Oakey | Corner of Kearneys Rd and Warrego Hwy | HP to AS1697 | 1050 | 1000 |
| Toowoomba | Hermitage Road | HP to AS1697<br>300 | 1050<br>4200 | 1000<br>1000 |

### 10.3.2 High Pressure Polyethylene System

Approximately 303 kilometres of the Network is high pressure PE. Pipe sizing ranges from 20 mm to 160 mm with the Toowoomba low and medium pressure system gradually being renewed with high pressure PE. Oakey township operating pressure is currently 140 kPa with Toowoomba township operating at 170 kPa. The spur line from the Oakey Gate Station to Purrawanda is 100mm and 160mm Class 700 PE operating at 680 kPa.

### 10.3.3 Medium Pressure System

Medium pressure systems operate within the Toowoomba Network and consist of PVC, PE and steel mains ranging in size from 32 mm to 150 mm.

### 10.3.4 Low Pressure System

The low pressure dry gas systems are supplied via a district regulator stations located in Laundry Street, Toowoomba. Low pressure gas mains are generally cast iron unprotected steel and PVC and vary in size from 32 mm to 300 mm.

## 10.4 Allgas Distribution Network – South Coast Region

The south coast distribution Network extends from the Albert River in the North to Benora Point (Tweed Heads) in New South Wales in the South. The Network consists of a supply pipeline from the Albert River to Reedy Creek with distribution in the Yatala industrial areas and in the main residential/commercial areas from Runaway Bay to Coolangatta and Tweed Heads. The Network consists of approximately 158 kilometres of high pressure steel mains and 294 kilometres of high pressure PE mains.

The natural gas supply for the South Coast Region is from the Gowan Road Gate Station at Runcorn (Brisbane). A Metering and pressure reduction facility is installed at Ashmore Rd, Ernest.

### 10.4.1 High Pressure Steel System

The high pressure Network consists of Class 150, 300 and 600 steel pipelines as listed on Table 10.4. The maximum operating pressure is set at the Gowan Road Gate Station. Class 600 and Class 300 mains operate at the same pressure, while Class 150 mains are regulated by district regulators at the connection points to the Class 300 and Class 600 mains. Operating pressures of the various systems are listed below:

**Table 10.4: High Pressure Steel System**

| Class | MAOP (kPa) | Operating Pressure (kPa) | Comments |
|---|---|---|---|
| 600 | 7800 | 3600 | Operating pressures may be increased as demand requires |
| 300 | 4200 | 3600 | |
| 150 | 1200 | 900 | |

The Class 600 and 300 system is basically a supply main running from the Gowan Road Gate Station south and parallel to the Pacific Highway through to the Ashmore Rd (sub-gate) Station and terminating at Reedy Creek.

### 10.4.2 High Pressure Polyethylene System

The Network is comprised of polyethylene in sizes of 40, 63, 90 and 110 mm diameter. This system operates at pressures between 200 to 350 kPa with an MAOP of 500 kPa.

## 10.5 System Load Profile

The following table provides information about the system load profile as required by the Code.

**Table 10.5: Gate Station Volumes (Ratio of monthly volume /minimum volume)**

| | Oakey | TWBA | Ellen grove | Runcorn 1 | Runcorn 2 | Mt Gravatt | Tingalpa | Doboy | Dinmore |
|---|---|---|---|---|---|---|---|---|---|
| **Jul 04** | 1.60 | 1.78 | 1.25 | 1.53 | 1.40 | 1.52 | 1.29 | 1.22 | 1.37 |
| **Aug 04** | 1.66 | 1.75 | 1.24 | 1.47 | 1.38 | 1.56 | 1.28 | 1.19 | 1.40 |
| **Sept 04** | 1.61 | 1.49 | 1.21 | 1.43 | 1.31 | 1.43 | 1.22 | 1.17 | 1.33 |
| **Oct 04** | 1.35 | 1.36 | 1.19 | 1.31 | 1.22 | 1.43 | 1.18 | 1.16 | 1.37 |
| **Nov 04** | 1.31 | 1.35 | 1.13 | 1.18 | 1.19 | 1.35 | 1.10 | 1.20 | 1.32 |
| **Dec 04** | 1.00 | 1.15 | 1.02 | 1.00 | 1.07 | 1.12 | 1.10 | 1.09 | 1.26 |
| **Jan 05** | 1.01 | 1.00 | 1.00 | 1.05 | 1.00 | 1.34 | 1.06 | 1.00 | 1.21 |
| **Feb 05** | 1.12 | 1.00 | 1.02 | 1.06 | 1.01 | 1.23 | 1.00 | 1.03 | 1.00 |
| **Mar 05** | 1.18 | 1.12 | 1.13 | 1.16 | 1.14 | 1.40 | 1.13 | 1.18 | 1.23 |
| **Apr 05** | 1.12 | 1.09 | 1.01 | 1.18 | 1.15 | 1.03 | 1.15 | 1.14 | 1.27 |
| **May 05** | 1.35 | 1.43 | 1.23 | 1.32 | 1.33 | 1.00 | 1.26 | 1.25 | 1.16 |
| **Jun 05** | 1.42 | 1.60 | 1.19 | 1.32 | 1.35 | 1.02 | 1.22 | 1.24 | 1.34 |

## 10.6 Gate Stations, District Regulators and SCADA

### 10.6.1 Gate Stations and District Regulators

Gate stations and district regulators are located throughout the system. The regulator stations generally consist of two regulators in series which employ an active monitor regulator configuration to ensure that security of supply and safe operating pressures are maintained in the system at all times. In the low pressure areas, a series of single regulators feed the low pressure area. In this instance, the supply pressure to the district regulator is usually not greater than 35 kPa. Failure of a low pressure regulator (these regulators normally fail closed) will generally not cause a problem because it is only one of several regulators feeding the same area.

Gate stations are located above ground. District regulator stations are generally located in underground pits. Gate stations are generally located on company-owned land or on dedicated pipeline easements whereas district regulators are generally located within road reserves, i.e. on nature strips.

Both the gate stations and district regulators are 100% pneumatically-controlled, i.e. all systems are operated exclusively on pressurised natural gas from the supply pipeline. Filtration systems are provided to protect the regulators as well as the associated pneumatic control systems from any foreign matter that may potentially enter the system. Isolation valving is provided for routine maintenance activities and for emergency purposes.

#### 10.6.2 SCADA Remote Monitoring

The gate stations which supply the Network are fitted with an automatic “dial-up by exception” system which monitors critical station operating parameters such as inlet and outlet pressures, gas temperature, station flow, unauthorised entry, etc. Excursions beyond preset limits initiate the automatic dial-up system to signal an alarm condition. Allgas staff that monitor the system are then able to dispatch field personnel to the site to assess and rectify any potential abnormal operating condition. In addition, Allgas provides roving pipeline patrols which perform regular spot checks and inspections regarding activities along the pipeline easement and critical Network facilities.

# ATTACHMENT 1:
# ALLGAS PRICING ZONE MAPS

| | |
|---|---|
| Map A: | Brisbane Region (includes Zones 1, 2 and 3) |
| Map B: | Brisbane Region (includes Zones 1, 2 and 3) |
| Map C: | South Coast Region (includes Zones 4, 5 and 6) |
| Map D: | South Coast Region (includes Zones 4, 5 and 6) |
| Map E: | Toowoomba (includes Zones 7 and 8) |
| Map F: | Oakey (includes Zones 9 and 10) |

# ATTACHMENT 2:
# ALLGAS DISTRIBUTION NETWORK MAPS

| | |
|---|---|
| Map 1: | South East Queensland 1 - Brisbane Network |
| Map 2: | South East Queensland 2 - South Coast Network |
| Map 3: | Western Region 1 - Toowoomba Network |
| Map 4: | Western Region 2 - Oakey Network |