Jemena Gas Networks (NSW) Ltd

Access Arrangement Information

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Table of Contents

Overview **xv**

Events and outcomes during the current access arrangement period xvi

Corporate ownership *xvi*

Demand growth *xvi*

Expenditure *xvi*

Outsourcing *xvii*

Our changing business environment xvii

Policy and regulatory developments *xviii*

Expected demand and customer growth *xviii*

Our plans for the future xix

Opportunities for marketing *xix*

Capital program *xix*

Cost of capital *xx*

Services *xxi*

Pricing *xxi*

Structure of this AAI xxii

1 Introduction **1**

1.1 Purpose of JGN's access arrangement 1

1.2 Purpose of this access arrangement information 2

1.3 Previous regulatory decisions 2

1.4 Guiding legislative provisions 4

1.5 JGN existing regulatory obligations 5

1.6 RIN and rule 72 requirements 8

2 Jemena Gas Networks **9**

2.1 Description of the Jemena Gas Networks 9

2.1.1 Background *9*

2.1.2 Current configuration and operation *10*

2.1.3 Users and services *12*

2.1.4 Customers *13*

2.2 Technical regulation 13

2.2.1 Reticulator's authorisation 13

2.2.2 Pipeline licences 14

2.2.3 Metering regulation 14

2.3 Network ownership context 14

2.4 Classification of the JGN pipelines 16

2.5 Service provider 16

2.6 Associate contracts 17

2.7 New external factors affecting JGN's business 17

2.7.1 Carbon trading 17

2.7.2 Fugitive emissions 19

2.7.3 Policies that influence end use 20

2.7.4 Expert reports 21

2.7.5 Energy market and regulatory developments 22

2.8 RIN and rule 72 requirements 23

3 Delivery of JGN activities 25

3.1 Summary 25

3.2 Structure of JGN management 26

3.4 RIN and rule 72 requirements 39

4 Current performance 41

4.1 Summary 41

4.2 Customer numbers, demand and volume 42

4.3 Operating expenditure 45

4.4 Capital expenditure 47

4.5 JGN's key performance indicators 50

4.5.1 Current AA period 50

4.6 RIN and rule 72 requirements 51

5 Demand forecasts 53

5.1 Summary 54

5.2 Law and rules requirements 55

5.3 Summary forecast demand 56

5.4 Basis of demand forecasts 57

5.4.1 Independent expert terms of reference 57

5.4.2 NIEIR economic forecasts 58

5.5 NIEIR demand forecast approach 58

5.5.1 NIEIR gas forecast summary 59

5.6 Overview of forecast results 60

5.6.1 Volume customer forecast 60

5.6.2 Demand customer forecast 60

5.7 NIEIR methodological approach 60

5.7.1 Information supplied by JGN 60

5.7.2 Overall modelling approach 61

5.7.3 Key economic inputs to NIEIR gas model 61

5.7.4 Key outputs from the NIEIR model 62

5.8 Factors affecting load forecasts 64

5.8.1 Weather normalisation of JGN gas data 64

5.8.2 Existing and new residential customer usage 65

5.8.3 Gas usage in New South Wales 66

5.8.4 Gas prices and the CPRS 66

5.8.5 Policies relating to gas (and electricity) consumption in NSW 66

5.9 JGN final forecast and adjustments 67

5.9.1 Residential demand adjustment 67

5.9.3 Small business and demand customer new connections adjustment *68*

5.9.4 JGN total forecast *69*

5.10 Use of demand forecasts in JGN's AAI 70

5.10.1 Customer categories and tariff classes *70*

5.10.2 Development of capex and opex forecasts *70*

5.11 RIN and rule 72 requirements 72

6 Forecast operating expenditure **74**

6.1 Summary 75

6.2 Law and rules requirements 76

6.3 Base year roll-forward approach 77

6.4 Application of the base year roll-forward approach 78

6.4.1 Collecting historical base year costs *78*

6.4.2 Adjusting the base year *79*

6.4.3 Rolling forward the base year *81*

6.5 JGN forecast non-O&M costs 83

6.5.1 Administration and overheads *85*

6.5.2 Government levies *86*

6.5.3 Marketing *86*

6.5.4 Unaccounted for gas *88*

6.5.5 Self insurance *91*

6.5.6 Debt and equity raising costs *92*

6.6 JGN's operating and maintenance costs 93

6.7 Rule compliance 96

6.8 Key performance indicators for the next AA period 99

6.9 RIN and rule 72 requirements 100

7 Forecast Capital expenditure **103**

7.1 Summary 103

7.2 Law and rules requirements 105

7.3 JGN capital planning 106

7.3.1 Project identification *106*

7.3.2 Project governance *106*

7.3.3 Asset management plan *107*

7.3.4 Information technology plan *110*

7.4 Distribution forecast methodology 111

7.4.1 Network capital expenditure *112*

7.4.2 Non-network forecast methodology *115*

7.5 Forecast capex 116

7.6 Rule compliance 117

7.6.1 Expert review of network capex *117*

7.6.2 Expert review of IT capex *118*

7.8 RIN and rule 72 requirements 119

8 Regulatory Asset Base **121**

8.1 Summary 121

8.2 Law and rules requirements 122

8.3 Opening capital base for the current AA period 123

8.4 Closing capital base for the current AA period 124

8.5 Projected capital base in the next AA period 127

8.6 Capital contributions 129

8.7 Disposals 130

8.8 Capital redundancy policy 130

8.9 RIN and rule 72 requirements 131

9 Cost of Capital **134**

9.1 Summary 135

9.2 Rule requirements 136

9.3 Background 137

9.3.1 Factors affecting JGN's cost of capital *137*

9.4 Treatment of tax 138

9.5 Business risk 138

9.6 Weighted average cost of capital model 140

9.6.1 WACC proposal *140*

9.6.2 Cost of equity proposal *141*

9.6.3 Cost of debt proposal *145*

9.7 Weighted average cost of capital parameters 146

9.7.1 Inflation 148

9.7.2 Gearing 148

9.7.3 Nominal risk free rate 149

9.7.4 Market risk premium 149

9.7.5 Fama-French factors and betas 149

9.7.6 Debt margin 149

9.7.7 Dividend imputation 149

9.7.8 Tax rate on equity 151

9.8 RIN and rule 72 requirements 152

10 Depreciation 154

10.1 Summary 154

10.2 Law and rules requirements 154

10.3 Assumptions on economic life of assets for regulatory depreciation 155

10.4 Depreciation and accumulated depreciation 157

10.5 RIN and rule 72 requirements 158

11 Incentive mechanisms 160

11.1 Summary 160

11.2 Law and rules requirements 160

11.3 Existing incentive mechanisms 161

11.4 Proposed incentive mechanisms 162

11.4.1 Market expansion mechanism 162

11.5 RIN and rule 72 requirements 163

12 Revenue requirement 164

12.1 Summary 164

12.2 RIN and rule 72 requirements 165

13 Services 166

13.1 Summary 167

13.2 Rule requirements 167

13.3 Background 168

13.4 Proposed reference services 168

		13.4.1 Haulage service	*169*
		13.4.2 Meter data service	*169*
	13.5	Proposed non-reference services and ancillary fees	170
		13.5.1 Non-reference services	*170*
		13.5.2 Contractual transition and legacy services	*170*
		13.5.3 Ancillary fees	*172*
	13.6	Reasons for changes in reference services	173
		13.6.1 Comparison to existing reference services	*174*
	13.7	Cost allocation to services	174
		13.7.1 Overview	*175*
		13.7.2 Capital allocations	*176*
		13.7.3 Operating cost allocations	*176*
	13.8	Price path	177
	13.9	RIN and rule 72 requirements	179
14	**Reference tariffs**		**180**
	14.1	Summary	180
	14.2	Law and rules requirements	181
	14.3	Tariff classes	182
		14.3.1 Volume tariff classes	*182*
		14.3.2 Demand tariff classes	*183*
		14.3.3 Transaction costs	*184*
		14.3.4 Ability to respond to price signals	*185*
	14.4	Efficient pricing	186
		14.4.1 Tariff efficiency	*186*
		14.4.2 Long run marginal cost	*190*
	14.6	RIN and rule 72 requirements	195
15	**Price control formulae**		**197**
	15.1	Summary	197
	15.2	Rule requirements	198
	15.3	Background and reasons for change	199
	15.4	Haulage reference service	201

15.4.1 Tariff variation mechanism *201*

15.4.2 Tariff variation process *202*

15.4.3 Transitional measures *202*

15.5 Other reference and non-reference services 203

15.5.1 Tariff variation mechanism *203*

15.5.2 Tariff variation process *204*

15.6 RIN and rule 72 requirements 204

16 Pass through events and mechanisms 205

16.1 Summary 206

16.2 Rule requirements 207

16.3 Current access arrangement 207

16.4 Criteria for assessing pass through events 207

16.5 Annual tariff variation factors 208

16.5.1 Unaccounted for gas *208*

16.5.2 Weather effects *210*

16.6 Proposed pass through events 210

16.6.1 Change in tax event *211*

16.6.2 License fees and statutory charges *211*

16.6.3 Regulatory events *212*

16.6.4 National energy customer framework *212*

16.6.5 National gas connections framework *216*

16.6.6 Australian Energy Market Operator *217*

16.6.7 Short term trading market *218*

16.6.8 Financial failure of a retailer *219*

16.6.9 Retailer of last resort event *219*

16.6.10 Business continuity *220*

16.7 RIN and rule 72 requirements 220

17 Terms and conditions 222

17.1 Changes to form of terms and conditions 222

17.2 Changes to substance of terms and conditions 223

17.2.1 Simplified reference services *223*

17.2.2 Rolling contract term *223*

17.2.3 Customer “churn” *223*

17.2.4 Transitional provisions *223*

17.2.5 Balancing *224*

Glossary **225**

List of appendices **230**

List of Tables

Table 1-1: General NGL and NGR provisions relevant to JGN's AA 4

Table 1-2: Industry-specific regulatory obligations relevant to JGN AA 6

Table 1-3: Summary of RIN responses 8

Table 2-1: Customers and load by region during 2008-09 13

Table 2-2: Carbon credit forecasts 19

Table 2-3: Reports addressing effects of CPRS on JGN demand and cost forecasts 22

Table 2-4: Summary of RIN responses 23

Table 3-1: Scope of management activities 27

Table 3-2: AMA services 31

Table 3-3: Allocation of risk in the AMA 34

Table 3-4: Summary of RIN responses 39

Table 4-1: Customer numbers during the current AA period 42

Table 4-2: Minimum, maximum and average daily load total JGN network 2005-06 to 2007-08 (TJ) 43

Table 4-3: Average daily gas load - volume and demand customers and MDQ for demand customers for current AA period (TJ) 43

Table 4-4: Gas load by customer type and tariff for current AA period (TJ) 43

Table 4-5: Forecasts of total gas load compared with actual (TJ) 44

Table 4-6: Forecasts of volume customers' gas load compared with actual and current estimates (TJ) 45

Table 4-7: Allowed non-capital costs compared with actuals and JGN's currently estimated and forecast outcomes 47

Table 4-8: Allowed capital costs compared with actuals and JGN's currently estimated and forecast outcomes 49

Table 4-9: Analysis of variance between allowed and actual capex over 2005-06 to 2008-09 50

Table 4-10: Trunk segment KPIs: Operating cost per kilometre ($) 50

Table 4-11: Distribution segment KPIs: Operating cost per metre and cost per customer site ($) 51

Table 4-12: Summary of RIN responses 51

Table 5-1: Forecast customer numbers by type and tariff class for next AA period 56

Table 5-2: Average load volume and demand customers next AA period and MDQ demand customers (TJ) 56

Table 5-3: Load by customer type and tariff for next AA period (TJ) 56

Table 5-4: Summary of NIEIR gas forecast over next AA period (Tables 5.1-5.4 of NIEIR report) 59

Table 5-5: NIEIR economic forecast NSW – macroeconomic aggregates and selected indicators (per cent change) (Table 3.2 NIEIR) 61

Table 5-6: NIEIR weather normalisation (TJ) (Table 4.2 NIEIR) 65

Table 5-7: Average residential customer usage in 2008-09 (GJ) (Table 4.3 NIEIR) 65

Table 5–8: Adjustment to annual gas usage demand customers (TJ) – year ending 30 June 68

Table 5–9: Adjustment to forecast MDQ demand customers (TJ) – year ending 30 June 68

Table 5-10: Number of new connections small business and demand customers – year ending 30 June 69

Table 5-11: JGN total gas forecast 2008-09 to 2014-15 69

Table 5-12: Summary of RIN responses 72

Table 6-1: JGN forecast opex 75

Table 6-2: JAM O&M one-off costs ($million, $2009) 80

Table 6-3: JGN O&M one-off costs ($million, $2009) 81

Table 6-4: Opex escalation factors for JGN, (per cent, real) 82

Table 6-5: Effect of emissions trading scheme on escalation factors (per cent) 83

Table 6-6: JGN forecast operating costs excluding O&M over next AA period 84

Table 6-7: The current marketing program costs for 2008-09 88

Table 6-8: Forecast marketing opex costs 88

Table 6-9: Forecast UAG costs 89

Table 6-10: Emission permit price 91

Table 6-11: JGN self insurance events (real, $nominal as at 1 January 2009) 92

Table 6-12: JGN forecast O&M costs over next AA period 93

Table 6-13: Forecast site remediation costs over next AA period 96

Table 6-14: Proposed KPIs: Operating cost per metre and cost per customer site ($) 100

Table 6-15: Summary of RIN responses 100

Table 7-1: JGN forecast capex 104

Table 7-2: Capital project governance gates 107

Table 7-3: Key drivers and description 108

Table 7-4: Forecast methods for network capex 113

Table 7-5: Forecast methods of non-network capex 115

Table 7-6: Forecast capex over the next AA period 116

Table 7-7: Summary of RIN responses 119

Table 8-1: Forecast value of RAB at 30 June 2015 ($nominal) 122

Table 8-2: JGN's closing RAB as at 30 June 2005 ($nominal) 124

Table 8-3: Increase in consumer price index 124

Table 8-4: Roll forward of combined total capital base over current AA period ($nominal) 125

Table 8-5: Roll forward of Wilton to Wollongong trunk pipeline capital base over current AA period ($nominal) 126

Table 8-6: Roll forward of Wilton to Newcastle trunk pipeline capital base over current AA period ($nominal) 126

Table 8-7: Roll forward of NSW distribution system capital base over current AA period ($nominal) 126

Table 8-8: Roll forward of combined total capital base over next AA period ($nominal) 127

Table 8-9: Roll forward of Wilton to Wollongong capital base over next AA period ($nominal) 127

Table 8-10: Roll forward of Wilton to Newcastle trunk pipeline capital base over next AA period ($nominal) 128

Table 8-11: Roll forward of NSW distribution system capital base over next AA period ($nominal) 129

Table 8-12: Capital contributions over the current AA period ($nominal) 130

Table 8-13: Summary of RIN responses 131

Table 9-1: JGN's proposed WACC Parameters 135

Table 9-2: Domestic Fama-French three-factor model 144

Table 9-3: Debt premium 146

Table 9-4: JGN's proposed WACC parameters for the next AA period 147

Table 9-5: Forecast Inflation 148

Table 9-6: Summary of RIN responses 152

Table 10-1: Forecast depreciation over next AA period ($nominal) 154

Table 10-2: Economic lives of JGN assets 156

Table 10-3: Regulatory depreciation as at 30 June 2010 157

Table 10-4: Forecast depreciation over next AA period ($nominal) 158

Table 10-5: Summary of RIN responses 158

Table 11-1: Summary of RIN responses 163

Table 12-1: JGN revenue requirement 164

Table 12-2: Summary of RIN responses 165

Table 13-1: Summary of reference services 174

Table 13-2: Revenue and cost alignment 177

Table 13-3: Price path 178

Table 13-4: Summary of RIN responses 179

Table 14-1: Stand alone costs compared to expected revenue ($) 187

Table 14-2: Avoidable costs compared to expected revenue ($) 188

Table 14-4: RIN response 195

Table 15-1: RIN response 204

Table 16-1: Summary of JGN's approach to managing highly uncertain risk events 206

Table 16-2: RIN requirements 220

List of Figures

Figure 2-1: JGN network overview map 11

Figure 2-2: JGN ownership context 15

Figure 3-1: JGN management structure 27

Figure 3-2: AMA incentive arrangements 37

Figure 4-1: JGN NSW gas load all customers 44

Figure 4-2: JGN historic opex ($2010) 46

Figure 4-3: Comparison of JGN's actual capex to allowance 48

Figure 5-1: NIEIR's regional energy model (NIEIR figure 4.2) 62

Figure 6.1: JGN in-house management and other non-O&M costs 85

Figure 6.2: Representative base year O&M costs 94

Figure 6-3: JGN and Victorian gas distributors' partial factor productivity indices, 1998-2009 98

Figure 6-4: JGN and Victorian gas distributors' multilateral opex partial factor productivity indices, 1998-2009 99

Figure 13-1: Distribution cost allocation requirements 175

Figure 13-2: JGN's smoothed revenue versus cost of service 178

Figure 14-1: Efficient bounds for expected revenues, demand tariffs 189

Figure 14-2: Efficient bounds for expected revenues, volume tariffs 190

Overview

The revised access arrangement that accompanies this access arrangement information is the fourth edition of the instrument that regulates Jemena Gas Networks' (**JGN's**) pipeline services and prices. It builds upon previous revisions, with a number of substantial developments and increasing benefits to users and customers.

Earlier access arrangements have set JGN's regulatory asset base at a historically low proportion of its replacement cost, reduced customer cross-subsidies, and established ambitious efficiency expectations. This new version takes account of JGN's changing business environment and its plans to move forward and meet the challenges.

JGN's key business drivers are:

Ensuring the safe, reliable, efficient and environmentally responsible operation of its network

JGN is committed to providing safe and reliable supply of gas in NSW and to conduct its business in an efficient and environmentally responsible manner. This complements JGN's desire to obtain long term stable and sustainable returns from its asset.

Promoting better utilisation of the network

A fundamental element of enhancing the value of the network to users, customers and JGN is growing the numbers of consumers connected to the network and volumes they consume, especially when this growth displaces higher carbon alternatives. Growth in consumer numbers and volumes drives greater efficiency of operations, increased asset utilisation and, ultimately, lower prices for consumers and a more sustainable business for JGN.

JGN recognises that the best way to achieve this growth is to continually communicate the merits of natural gas and to actively identify and meet the needs of its users and customers.

Optimising capital investment

The JGN business is capital intensive with significant annual expenditure requirements. JGN optimises its capital expenditure by actively assessing its risk position, evaluating its options and selecting solutions that attain an optimal balance between risk and cost.

Events and outcomes during the current access arrangement period

Corporate ownership

Singapore Power, a long term investor in energy infrastructure, now owns JGN though its subsidiary SPI (Australia) Assets Pty Ltd (**SPIAA**).

In 2006, the Australian Gas Light Company (**AGL**) and Alinta conducted a transaction that resulted in, among other things, Alinta taking ownership of the AGL's New South Wales gas network and AGL retaining ownership of its retail arm. A year later, a consortium of Babcock and Brown and Singapore Power International (**SPI**) bought Alinta. Subsequently, SPI gained ownership of several of the former Alinta assets that now trade under the new Jemena brand. The largest of these include Jemena Gas Networks (NSW), Jemena Electricity Networks (Vic), Jemena Pipelines and Jemena Asset Management.

Demand growth

The demand for gas and the number of new connections to JGN's network have fallen considerably short of the forecasts that the Independent Pricing and Regulatory Tribunal (**IPART**) determined and used to set JGN's prices for the current access arrangement period. Consequently, JGN has under-recovered its revenue by a considerable amount over the current period.

Most noteworthy is that JGN's small customer sector demand is below the IPART forecast by 18 petajoules over the current period, or 10 per cent. This is a significant shortfall and has resulted in a revenue shortfall of about eight per cent relative to the approved cost of service.

JGN's experience shows how policy measures and other market trends can affect gas load, and how necessary it is to factor them into demand forecasts. Failure to give appropriate recognition to all significant factors can result in inaccurate forecasts, effectively denying JGN an opportunity to recover at least its efficient costs.

Expenditure

JGN has achieved operating cost efficiencies greater than those IPART forecast in its 2005 decision. JGN expects to incur operating expenditure over the current period of $633.7 million, which is 7.34 per cent below that allowed by IPART.

JGN has met its commitment to invest in capital works that extend the life and capacity of its network, and to maintain reliability using innovative solutions, many designed to defer more major reinforcements and contain expenditure within the regulatory alowance. Over the current period, JGN expects to invest $556.6 million, which is within 1.21 per cent of the amount IPART allowed in 2005.

Of particular note is the award-winning Sydney Primary Loop, which connects into the existing primary main network that distributes natural gas to homes and businesses across Sydney. This project was essential to securing Sydney's existing supply of natural gas, as well as planning for the long-term needs of the growing population.

Outsourcing

As part of the SPIAA group of companies, JGN has for many years had the benefit of outsourcing a large proportion of its asset management service to Jemena Asset Management (**JAM**, formerly Agility), a leader in the gas industry.

During 2009, JGN's management conducted a service model project. The objective of the project was to establish a formal asset management agreement (**AMA**) under which JGN can continue to procure asset management services at an efficient level of cost and with incentives aligned to ensure ongoing service and cost performance.

JGN initiated bilateral negotiations with JAM to develop their new AMA. The negotiation framework applied the same controls for competitively tendering work. The resultant agreement, which came into effect from 1 August 2009, creates a number of valuable outcomes for JGN:

- services and accountabilities are more clearly defined
- costs are transparent
- JAM has strong incentives to ensure it delivers JGN's required services at the lowest sustainable cost
- risk is allocated to the party that can best manage it
- JGN has certainty of asset management resourcing at least until the end of 2018.

Our changing business environment

JGN is facing a changing business environment.

Policy and regulatory developments

There are two key external factors that are affecting, or about to affect, JGN's operations and costs, and that JGN has taken into account when preparing its revised AA.

The Australian Government has a stated intention to implement carbon pricing and trading, fugitive emissions reporting, and other new policies—such as renewable energy target and national hot water schemes—that will significantly influence how customer use gas and change JGN's market trends.

In addition to this, several new market and regulatory developments will come into effect after JGN has lodged this submission: the national energy customer framework, the national framework for natural gas customer connections, the short term trading market, and consolidation of the activities of the new Australian Energy Market Operator. As the costs JGN will incur to participate in these are highly uncertain, JGN is proposing to use a simple pass through mechanism.

More strategically, JGN is proposing tariff reforms for large customers that will enhance the operation of the new short term trading market (**STTM**). The STTM will create a wholesale hub and allow the Sydney-Newcastle-Wollongong region to operate better as a single seamless market. The National Competition Council made this more possible when it recently granted JGN's request to classify its northern and southern trunks as distribution, and align them with the rest of the network.

Expected demand and customer growth

Given the importance of accurate demand forecasting, JGN has commissioned a highly-competent independent expert to develop forecasts.

The National Institute of Economic and Industry Research (**NIEIR**) expects that small customer gas usage will grow by only 0.9 per cent per year over 2009 to 2019 before taking account JGN's marketing program. NIEIR attributes this level of growth to price and market effects of the carbon pollution reduction scheme, Commonwealth and NSW energy policies, and the increasing use of new more efficient gas appliances.

NIEIR also forecasts a decline in large customer usage for JGN on average by 0.4 per cent per year, mainly due to a general economic downturn, and in 2012-13 due to the introduction of emissions trading.

Weather will continue to be a factor that influences the level of demand, one which is difficult to predict. To mitigate financial risk to JGN and customers, JGN is proposing a symmetrical mechanism that will adjust JGN's revenue if the weather is hotter or colder (and demand is lower or higher, respectively) than expected.

This would ensure JGN experiences neither wind-fall gains nor losses due to the weather, a factor over which JGN has no control.

Our plans for the future

In response to our growing market and increasingly challenging business environment, JGN has plans to move forward with a new capital program and reforms to its services and pricing.

Opportunities for marketing

JGN will continue the marketing program it has developed over the past two years—including the popular *Natural Gas The Natural Choice* campaign and targeted incentives for appliance installers—with the primary aim of significantly increasing the sale and installation of gas heating appliances in NSW. It is doing this by establishing natural gas as a highly desirable and environmentally friendly energy option.

JGN is targeting a 50 per cent growth in gas heating appliance connections, which would translate to increased gas consumption of approximately 150 TJ per year. This can displace more carbon-intensive energy sources, increase network utilisation, and reduce average prices to customers.

Capital program

JGN plans to take a balanced approach and strike an appropriate balance between operational and maintenance expenditure, new capital works and risk.

With the expected level of demand and new connections, JGN can only maintain its current level of maintenance activity and unplanned outages if it makes substantial investments in new capacity and in network reinforcement. During the current access period JGN has achieved significant capital cost savings through innovative short term measures to maintain reliability and defer major capacity upgrades. An extensive review and analysis of JGN's assets over the past three years has taken account of JGN's demand and customer growth, the age of its assets, and their impact on continuity of supply. JGN intends to make its investments just-in-time with efficient solutions to meet its market's needs in metropolitan and country areas.

JGN also intends to implement new information systems to attain efficiency and capability standards consistent with today's good industry practice and to meet the increasing requirements of the wholesale and retail gas market. An extensive assessment has found that the life and usefulness of JGN's information technology infrastructure and applications are coming to an end after many years of service.

Accordingly, JGN plans to invest a total of $885.2 million in its network and information technology over the next period. Major new projects include:

- *Wakehurst Parkway* – JGN will build a new secondary main to Warringah to support an increasingly complex and loaded system that serves an expanding load along the length of Sydney's northern beaches.

- *Blue Mountains* – A new primary main will be installed across the Nepean River at Emu Plains to provide the capacity needed to connect new customers in the Blue Mountains, and to improve the reliability of supply to existing customers.

- *Package off-take stations in country areas* – JGN will upgrade several package off-take stations and bath heaters for the Marsden to Dubbo and Junee to Griffith laterals to accommodate increasing operating pressures on the Moomba to Sydney pipeline.

- *Customer service, billing and metering IT* – JGN will replace its core operating system, the 25 year old in-house "GASS" application, with a combination of new works management modules, a market-sourced metering and billing application suite and in house development.

JGN's plans also include many smaller projects including those aimed at replacing and upgrading its ageing network and IT assets to ensure they continue to operate safely and reliably.

The financial capacity of JGN to undertake this vital work depends of the outcomes of its access arrangement revision, most significantly the cost of capital allowed.

Additional market expansion

There is a substantial opportunity for JGN to invest beyond its current plans and start connecting customers in existing urban areas. Urban in-fill projects have the potential to provide more households with the benefits of natural gas and increase the utilisation and efficiency of the network as a whole. JGN has proposed an incentive mechanism that could provide it with a modestly higher return so that it can attract the additional capital required.

Cost of capital

The cost of capital set in JGN's access arrangement provides the main driver for efficient investment. Accordingly, the National Gas Rules require that it reflect the prevailing market conditions for funding a benchmark efficient gas distribution business with a benchmark capital structure and risk profile.

Strong evidence JGN has provided with this submission shows that the Fama-French model provides an estimate of the cost of equity that better reflects the prevailing conditions in the market for funds than the Sharpe-Lintner model. JGN has set its cost of capital using the Fama-French three-factor model.

It has also set its cost of capital with regard to gas distributors being inherently more risky businesses than electricity distributors, with higher debt premia.

Services

While JGN will continue to offer users the same services for small customers, JGN will simplify its service offering for large customers. In conjunction with the meter data service, JGN will offer one haulage reference service for all customers with separate customer categories and tariff classes.

By doing this, JGN can better support the gas market objective as it reduces the administrative burden on gas market participants. It aligns JGN's service offering with distributors in other jurisdictions and will make it easier for retailers to operate in multiple jurisdictions.

JGN will continue to offer its previous 'legacy' services. However, as effective commercial operation of the network depends on the swift take-up of its new reference services, JGN will provide an incentive for users to do so.

Pricing

JGN will also continue to provide the same reference tariff structures for small customers, which currently represent 88 per cent of its revenue.

For large customers, JGN will structure its prices to recover trunk costs in a way that complements the STTM hub arrangements and market definition. The proposed pricing will ensure that all future sources of gas and transmission connection points have the same opportunity to participate in this market. It will also avoid the situation where JGN's network prices drive separation in the wholesale gas price between coastal regions of Sydney, Wollongong, Central Coast and Newcastle.

To further enhance the operation of an efficient gas market, JGN is establishing an interruptible supply tariff to facilitate load curtailment during supply constraint events. This type of curtailment will increase the security of supply to all customers.

JGN also intends to remove perverse incentives at the threshold between volume and demand customers by introducing a minimum demand bill, which it will introduce progressively to smooth the transition.

A tariff basket approach to pricing will give JGN the flexibility to adjust its pricing between tariff classes during the next period and respond to actual growth in each market segment. This approach reflects the good practice in other jurisdictions.

Structure of this AAI

This AAI is presented under the following sections:

- Part 1 describes JGN's network, its history of regulated access, the regulatory framework and operating environment, and the manner in which JGN incurs costs (chapters 1 to 3)
- Part 2 sets out JGN's current and forecast demand and costs (chapters 4 to 12)
- Part 3 details JGN's proposed revenue, services and pricing (chapters 13 to 17).

Part 1 – JGN operating context

1 Introduction

This Access Arrangement Information (**AAI**) has been prepared by Jemena Gas Networks (NSW) Ltd (**JGN**) (ACN 003 004 322), which is a public company registered in New South Wales (**NSW**). JGN is the owner, controller and operator of gas distribution networks in NSW (**JGN network**).

Chapter 1 describes the form and structure of JGN's access arrangement (**AA**) and AAI, and the regulatory arrangements that inform the content of these documents. The chapter is structured as follows:

- *Section 1.1 Purpose of JGN's access arrangement* – describes the purpose of JGN's AA
- *Section 1.2 Purpose of this access arrangement information* – explains the purpose of JGN's AAI
- *Section 1.3 Previous regulatory decisions* – provides insights from the previous regulatory decisions
- *Section 1.4 Guiding legislative provisions* – outlines legislative provisions that guide JGN's AA and AAI
- *Section 1.5 JGN existing regulatory obligations* – describes JGN's current regulatory obligations
- *Section 1.6 RIN and rule 72 requirements* – maps the AER Regulatory Information Notice (**RIN**) and National Gas Rules (**NGR**) rule 72 requirements to relevant sections in this chapter.

1.1 Purpose of JGN's access arrangement

JGN's AA details the commercial and technical terms upon which JGN offers reference services to users and prospective users by means of four covered pipelines:

- the NSW distribution system
- the Central West distribution system
- Wilton to Newcastle distribution pipeline
- Wilton to Wollongong distribution pipeline.

On 5 June 2009, the AER directed JGN to consolidate the terms of access for these four covered pipelines into one AA.

JGN's AA will apply from 1 July 2010 to 30 June 2015 which is the next access arrangement period (**next AA period**) and the fourth one for JGN.

1.2 Purpose of this access arrangement information

This AAI contains information that enables users and prospective users to understand the derivation of the elements of JGN's AA. It should be read in conjunction with JGN's access arrangement submission, which includes JGN's AA and access arrangement changes description set out in Appendix 1.1.

This AAI is structured in three parts. These consider JGN and its operating context, JGN's cost of service and demand, and JGN's pricing arrangements.

All monetary amounts presented in this AAI are expressed in real 2010 dollars, are in millions of dollars and apply to 1 July to 30 June regulatory years unless otherwise stated.

Response to regulatory information notice

On 12 May 2009, the AER served a RIN on JGN under section 48(1)(a) of the National Gas Law (**NGL**), requiring JGN to provide, prepare, maintain or keep information in a manner and form specified in the notice.

JGN has complied with the RIN through the information provided in this AAI and other parts of the access arrangement submission. JGN has also provided this information to address the requirements of rule 72 of the NGR.

Further information is provided in supporting attachments.

1.3 Previous regulatory decisions

JGN's network has been subject to independent economic regulation by IPART since 1996. JGN notes that key components of its AA have been the subject of several major regulatory investigations by IPART and of public consultation. IPART has made a number of key past decisions which have flowed through to subsequent regulatory periods, including:

Setting regulatory asset base

JGN's regulatory asset base (**RAB**) was set in 2000[1] at 75 per cent of depreciated optimised replacement cost. This is the second-lowest of the historical RAB decisions for gas pipelines by Australian regulators listed by the Scheme Register.[2] This historically low valuation has benefited, and will continue to benefit, users and consumers.

Rebalancing of network revenues

IPART oversaw a major rebalancing of network revenues between large customers and small customers, with the over-recovery from large customers being substantially unwound by the early 2000s. In the 2000 decision, real network revenue reduced from 1999-2000 to 2003-04 by 7.5 per cent, with the majority of this attributed to the large customer market. IPART projected real large customer prices to fall by 16 per cent per year on average over the period, with IPART stating that large customer prices 'are now set on a cost reflective basis.[3]

Decreasing expected efficiency gains

In the 2000 decision, IPART reduced controllable operating costs (before growth) by 28 per cent over 1999-2000 to 2003-04[4]. This was based largely on assumed efficiency savings of 3 per cent per year. In its 2005 decision, IPART accepted that JGN had become more efficient over time and that JGN's ability to implement efficiency gains had become harder to achieve. IPART accepted that forecast efficiency savings of 1.5 per cent per year for 2005-06 to 2009-10 were reasonable.[5]

Overestimating demand growth

In addition, JGN notes that prior to the 2004 draft decision, IPART's consultants had strongly queried the basis of JGN's assumptions about the effects of NSW Government policy on gas hot water usage. As a result, JGN increased its demand forecast to meet the consultant's opinions.[6] This revision had the ultimate effect of reducing network service prices. Actual demand for 2005-09 has fallen

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1 IPART, *Final Decision: Access Arrangement for AGL Gas Networks Limited Natural Gas System in NSW*, July 2000, p. 8. http://www.ipart.nsw.gov.au/files/Revised%20Access%20Arrangement%20for%20AGL%20Gas%20Networks%20-%20AGLGN%20-%20April%202005%20-%20Final%20Decision%20-%20PDF%20version.PDF

2 Based on information available from AEMC website for the Scheme Register for natural gas pipelines: http://aemc.gov.au/Gas/Scheme-Register/Pipeline-list-summary.html.

3 IPART, op, cit. pp 3-4.

4 IPART, op, cit. p. 10.

5 IPART Final Decision, *Revised Access Arrangement for AGL Gas Networks*, April 2005, p. 112.

6 IPART Draft Decision, *Revised Access Arrangement for AGL Gas Networks*, December 2004, p. 40.

short of JGN's original forecast and is significantly lower than IPART's allowed forecast. Chapter 4 provides more detail on this issue.

1.4 Guiding legislative provisions

In developing its AA, JGN must be guided by the national gas objective (**NGO**), the revenue and pricing principles in the NGL, and the provisions of particular rules. Likewise, the AER must be guided by these same provisions in its consideration of the AA.

Table 1-1 sets out the NGO and the provisions of the NGL and NGR to which JGN has had general regard in developing its AA proposal.

Table 1-1: General NGL and NGR provisions relevant to JGN's AA

Law or rule	Provision
NGO (NGL s. 23)	The national gas objective is to promote efficient investment in, and efficient use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, reliability and security of supply of natural gas.
Revenue and pricing principles (NGL s. 24)	(2) A service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in— a) providing reference services; and b) complying with a regulatory obligation or requirement or making a regulatory payment.
	(3) A service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides. The economic efficiency that should be promoted includes— a) efficient investment in, or in connection with, a pipeline with which the service provider provides reference services; and b) the efficient provision of pipeline services; and c) the efficient use of the pipeline.
	(4) Regard should be had to the capital base with respect to a pipeline adopted— a) in any previous— • full access arrangement decision; or • decision of a relevant regulator under section 2 of the gas code; b) in the rules.
	(5) A reference tariff should allow for a return commensurate with the regulatory and commercial risks involved in providing the reference service to which that tariff relates.
	(6) Regard should be had to the economic costs and risks of the potential for under and over investment by a service provider in a pipeline with which the service provider provides pipeline services.

Law or rule	Provision
	(7) Regard should be had to the economic costs and risks of the potential for under and over utilisation of a pipeline with which a service provider provides pipeline services.
Forecasts and estimates (NGR s. 74)	(1) Information in the nature of a forecast or estimate must be supported by a statement of the basis of the forecast or estimate. (2) A forecast or estimate: (a) must be arrived at on a reasonable basis; and (b) must represent the best forecast or estimate possible in the circumstances.

In addition to the general provisions above, there are provisions in the NGR which deal with particular elements of an AA proposal, such as capex and opex. These rules are cited in the relevant chapters of this AAI.

1.5 JGN existing regulatory obligations

As noted above, NGL s. 24(2)(b) requires that a service provider be given a reasonable opportunity to recover its efficient costs in complying with a regulatory obligation or requirement or making a regulatory payment.

JGN is subject to a wide range of regulatory obligations. Some of those arise under legislation such as the Corporations Act 2001 (Cwth), Commonwealth Taxation legislation, the Trade Practices Act 1974 (Cwth), and State-based Occupational Health and Safety, Employment, and Environmental legislation that applies to corporations generally. JGN incurs costs in complying with those generally-applicable requirements. Other regulatory obligations arise under industry-specific legislation.

There are a number of existing regulatory obligations on JGN which are certain, can be reasonably quantified in dollar terms, and for which JGN would expect cost recovery over the next AA period.

The following table outlines the principal industry-specific regulatory obligations that are generally accounted for in JGN's proposed costs. In some cases, such as retail market procedures under Australian Energy Market Operator (**AEMO**), there is potential for additional but unspecified costs to be imposed. Section 2.7 and chapter 16 elaborate on these issues.

Table 1-2: Industry-specific regulatory obligations relevant to JGN AA

Obligation source	Impact on business and costs
Gas Supply Act 1996 (NSW) (gas supply act)	The act requires, among other things, that a person who operates a gas distribution pipeline be authorised, and that the authorisation holder pay an annual authorisation fee.
Gas Reticulator Authorisation under the Gas Supply Act (NSW) 1996	JGN's authorisation is subject to a number of conditions, including that JGN must develop adopt and comply with a Network Code, and maintain prudent insurances.
Gas Supply (Gas Meters) Regulation 2002 (NSW)	The regulation requires that gas be metered, and imposes obligations in relation to the testing of gas meters prior to installation and when in service.
Gas Supply (Safety and Network Management) Regulation 2008 (NSW)	The regulation requires, among other things, that JGN: • design construct and operate its network in accordance with specified standards • maintain emergency response capabilities • establish gasfitting rules • establish and implement a Safety and Operating Plan which must be audited annually. The regulation also imposes obligations in relation to gas quality and gas testing.
JGN Network Code for Full Retail Competition (2002) (network code)	The Network Code documents certain important elements of the relationship between Network Operators and Retailers that are necessary to support the introduction of a fully competitive natural gas retail market. The Code imposes standards on JGN for, among other things, responding to users' enquiries, the provision of consumption and billing data, notification of planned interruptions, and timeliness of new connections.
Retail Market Procedures (NSW and ACT) (under AEMO)	The procedures set out how market participants will interact with one another through the Gas Retail Market Business System. The Procedures require JGN, among other things, to allocate delivery point identifiers and comply with specified timelines for collection and dissemination of data that is relevant to the operation of the gas market including daily nominations, consumption data, and information relating to connections, disconnections and transfers etc.

Obligation source	Impact on business and costs
National Gas Law and National Gas Rules 2008	The NGL and NGR together provide for the economic regulation of gas pipelines including the JGN network. Among other things, the NGL and NGR require JGN to: • submit an AA for approval • comply with ring fencing and related obligations • comply with market operation obligations and pay AEMO participant fees • report periodically and provide information to AER and AEMO.
Pipelines Act 1967 (NSW)	The Act requires that a person who constructs or operates a pipeline must be licensed. An annual licence fee is payable in respect of each licensed pipeline.
Pipelines Regulation 2005 (NSW)	The Regulation requires, among other things, that JGN: • design construct and operate its licensed pipelines in accordance with specified standards • establish and implement Environment Management and Safety and Operating Plans • report pipeline incidents and submit periodic reports. • Safety and Operating Plans must be audited each year.
NSW Pipeline Licence Nos 1, 2, 3, 7 and 8 under the Pipelines Act 1967	The licences require, among other things that JGN: • arrange and maintain appropriate insurances • operate and maintain corrosion protection equipment • mark and patrol each pipeline and maintain easements • maintain relationships with landowners.

1.6 RIN and rule 72 requirements

Table 1-3 sets out RIN requirements met in chapter 1. There are no rule 72 requirements met in chapter 1.

Table 1-3: Summary of RIN responses

RIN reference	RIN requirement	Where addressed in AAI
Details of service provider		
2.1.1	Provide in the access arrangement proposal submission the following information for all service providers of the pipeline: (a) Trading name (b) ACN (c) Type of service provider (owner, controller or operator) (d) Type of legal entity	Chapter 1

2 Jemena Gas Networks

As an aid to understanding the AA, this chapter describes the physical operation of the JGN gas distribution network, the services JGN offers, and gives an overview of regulatory oversight of the network.

This chapter is structured as follows:

- *Section 2.1 Description of Jemena Gas Networks* – describes JGN's network
- *Section 2.2 Technical regulation* – sets out technical regulation of the network
- *Section 2.3 Network ownership context* – describes the network ownership
- *Section 2.4 Classification of the JGN pipelines* – details pipeline classifications
- *Section 2.5 Service provider* – clarifies that JGN is the service provider
- *Section 2.7 RIN and rule 72 requirements* – maps the RIN and NGR rule 72 requirements to the relevant sections.

2.1 Description of the Jemena Gas Networks

This section provides an overview of the physical JGN network, the services provided, its users, and customers. It explains characteristics and emerging trends and opportunities that affect reference services and tariffs proposed in the AA.

2.1.1 Background

JGN provides natural gas transportation and associated services to users of the JGN network.

The JGN network has its origins in 1837 when the Australian Gas Light Company was formed to light the streets of Sydney. The network has grown through a combination of extensions, new developments and acquisitions. It now provides gas to more than 1,050,000 of its users' customers across Sydney, Newcastle, the Central Coast, and Wollongong, and over 20 country centres including those within the Central Tablelands, Central West, Southern Tablelands and Riverina districts.

2.1.2 Current configuration and operation

JGN's network is described in section 1.3 of its AA.

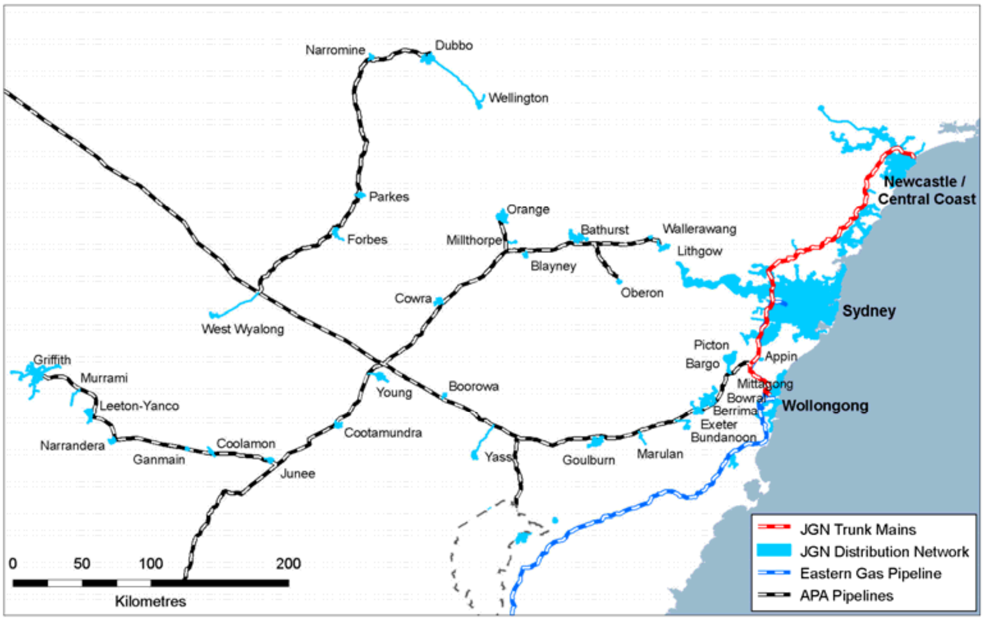
At present the section of the JGN network that serves Sydney, Newcastle and Wollongong has four receipt points through which it accepts gas from three principal sources:

- the Moomba to Sydney Pipeline (**MSP**), owned by the Australian Pipeline Trust and APT Investment Trust (**APA Group**), which principally transports gas produced in the Cooper basin to JGN's Wilton receipt point
- the Jemena-owned EGP, which principally transports gas produced in Bass Straight from the Longford plant in Victoria to:
  - the JGN's Horsley Park receipt point
  - the JGN's Port Kembla receipt point
- the Sydney Gas Company[7] (**SGC**), which injects local coal seam methane at the Rosalind Park receipt point near Campbelltown.

There are separate country receipt points (32 in all) for each of the country centres served by the JGN network. All of those centres are connected to the MSP or the Central West Pipeline, both owned by the APA Group.

[7] On 1 April, 2009, AGL Energy Limited announced that it had completed the compulsory acquisition of remaining shares in SGL (http://imagesignal.comsec.com.au/asxdata/20090401/pdf/00941156.pdf).

Figure 2-1: JGN network overview map



At each of these network receipt points, natural gas is physically transferred from the transmission pipeline/facility owner to JGN and commercially transferred from the shipper of gas on the transmission pipeline to the user who contracts with JGN for reticulation of the gas to customers or itself. Custody transfer quality meters are located at each of the JGN network's receipt points to measure the transfer of gas from the transmission pipeline/facility into the network.

The JGN network currently consists of approximately 267 km of trunk mains, 143 km of primary mains, 1,428 km of secondary mains, 22,596 km of medium and low pressure mains, 36 network receipt points, 27 trunk receiving stations, 14 primary regulating stations, and 575 district regulator sets.

The section of the JGN network that serves Sydney, Newcastle and Wollongong is balanced as a single network as are each of the network sections that serve country centres. 'Balancing' refers to arrangements that ensure that users in aggregate inject into the JGN network each day similar amounts of gas as they withdraw. This ensures that operating gas pressure in all parts of the reticulation network stay within technically acceptable limits. Under these arrangements, each user of a network section is responsible for the injection of enough gas to meet the demands of its customers on a daily basis. Balancing ensures that the balance of supply/demand to the network is managed and that there are commercially and technically feasible arrangements in place to supply operational balancing gas on each day.

2.1.3 Users and services

JGN hauls gas: it takes custody of users' gas at receipt points and distributes it to the premises of customers at delivery points on the network. JGN charges users for this service under contracts with them. JGN also provides delivery point metering infrastructure and information services to users to allow them to bill their customers. As part of its haulage service, JGN procures gas to replace unaccounted for gas (**UAG**) and allocates operational balancing gas.

JGN also undertakes certain activities for users that are ancillary to the reference services. JGN levies ancillary fees for these activities which include temporary disconnection and reconnection of supply and special meter reading.

As set out in the proposed AA, JGN offers to provide users with:

- two reference services:
  - haulage service – a service for the transportation of gas by JGN through the network to a single eligible delivery point for the use of a single customer
  - meter data service – a service for the provision of meter reading and on-site data and communication equipment to a delivery point
- two non-reference services:
  - interconnection of embedded network service – a service for connection points servicing multiple customers
  - negotiated services – a service involving non-reference connection terms and conditions
- multiple ancillary fees as set out in section 13.5.3
- legacy services:
  - for instances where an existing user does not immediately transition to the new Reference Service Agreement (**RSA**), and continues to receive a service requested and contracted as a reference service under a previous AA.

Currently JGN provides haulage and meter data services through contracts to nine users, five of whom are energy retailers, collectively supplying over 1,052,000 customers. The other four users are end users who contract directly with JGN for their haulage and meter data services. AGL Energy Limited is a gas retailer and the largest user of the JGN network.

2.1.4 Customers

JGN transports 66 petajoules (**PJ**) of gas per year to 414 large customers, who each consume more than 10 terajoules (**TJ**) per year. Reticulation of gas to these large customers accounts for 12 per cent of JGN's revenue as at March 2009. JGN transports 35 PJ of gas per year for users who supply the remaining customers, being those that consume less than 10 TJ of gas per year, and this provides 88 per cent of JGN's revenue as at March 2009.

The number of customers connected to the JGN network in 2009, and their gas consumption in that year, are given in Table 2-1.

Table 2-1: Customers and load by region during 2008-09

Region	Customers who use 10 TJ or more per year		Customers who use less than 10 TJ per year	
	Number	**Load (TJ)**	**Number**	**Load (TJ)**
Sydney	294	36, 597	823,061	27,275
Newcastle	60	18,884	89,480	2,378
Wollongong	13	5,976	55,479	1,377
Country	47	4,161	84,590	3,957
Total	**414**	**65,618**	**1,052, 610**	**34,987**

Note. Gas loads in this table are not weather adjusted.

Residential gas usage is principally for home heating, water heating and cooking. Accordingly, demand levels are affected by the weather. Residential penetration of gas in NSW is around 50 per cent.

Commercial premises use natural gas principally for water heating, cooking and other commercial appliances.

Industrial customers use natural gas as a source of energy for production processes, and, in some cases, as feedstock for fertiliser or petrochemical products.

2.2 Technical regulation

Three principal regimes of technical regulation apply to the JGN network.

2.2.1 Reticulator's authorisation

JGN currently holds a reticulator's authorisation to operate the JGN network as required by the Gas Supply Act 1996 (NSW) (**Gas Supply Act**). The authorisation is subject to certain conditions, including that JGN must develop adopt and comply with a Network Code[8], and maintain prudent insurances. JGN is also subject to the legal obligations of a reticulator pursuant to regulations made under the Gas Supply Act.

2.2.2 Pipeline licences

JGN holds licenses under the Pipelines Act 1967 (NSW) (**Pipelines Act**) for the following pipelines:

- Wilton to Horsley Park Natural Gas Pipeline (NSW:1)
- Wilton to Wollongong Natural Gas Pipeline (NSW:2)
- Horsley Park to Plumpton Natural Gas Pipeline (NSW:3)
- Plumpton to Killingworth Natural Gas Pipeline (NSW:7)
- Killingworth to Walsh Point Gas Pipeline (NSW:8).

Under the NSW Gas Supply Act, Pipelines Act and Pipelines Regulation 2005 (NSW) (**Pipelines Regulation**), JGN must produce and lodge a safety and operating plan to demonstrate sufficient management systems for safe operation of the gas distribution network and the pipelines.

For purposes of economic regulation, the pipelines described above have been classified as distribution pipelines for the purpose of the NGL. Section 2.4 elaborates on this classification.

2.2.3 Metering regulation

The NSW Department of Fair Trading administers regulations[9] that require the accurate metering of gas supply, meter testing (by distributors or other parties) to specific standards and the maintenance of the integrity of gas measurement equipment.

2.3 Network ownership context

The JGN network is owned by Jemena Gas Networks (NSW) Ltd, formerly named AGL Gas Networks Limited, and Alinta AGN Ltd.

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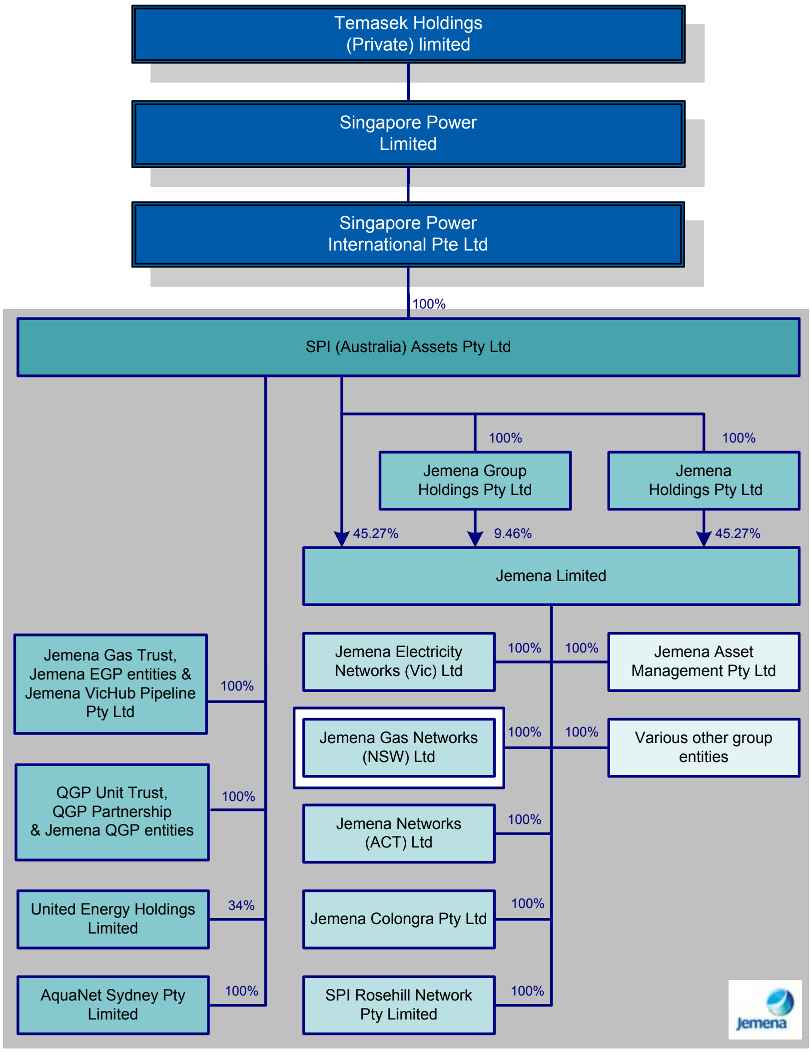
8 The Network Code sets minimum standards for the relationship between network operators and retailers. See http://www.jemena.com.au/operations/distribution/JGN/distributionNetworks/070502JemenaNetworkCode.pdf

9 *Gas Supply (Gas Meters) Regulation 2002*.

Ownership of JGN changed in October 2006, with Alinta Limited's acquisition of the Australian Gas Light Company (**AGL**), including AGL Gas Networks Limited (**AGLGN**). That company was then renamed Alinta AGN Ltd. Ownership changed again on 31 August 2007, when Singapore Power International acquired a portion of Alinta's assets including 100 per cent of the shares in Alinta AGN Ltd. The company was subsequently renamed Jemena Gas Networks (NSW) Ltd.

Figure 2-2 is a schematic diagram showing relevant elements of the group corporate structure in which JGN resides.

Figure 2-2: JGN ownership context



Notes:

1. Jemena Pipelines operates assets owned by Jemena Gas Trust, Jemena EGP entities, Jemena VicHub Pty, QGP Unit Trust, QGP Partnership and Jemena QGP entities: Eastern Gas Pipeline, VicHub and Queensland Gas Pipeline.
2. Jemena Networks (ACT) Ltd holds a 50 per cent interest in ActewAGL Distribution Partnership.

Some statutory references and past AA decisions still refer to Jemena Gas Networks (NSW) Ltd by its previous names.

2.4 Classification of the JGN pipelines

All pipelines within the JGN network are now classified as distribution pipelines. This section describes the background to that classification.

The gas code, which came into effect in NSW in August 1998, distinguished between different pipeline types to determine who would regulate each pipeline. Distribution networks were regulated within the individual states and territories, and the Australian Competition and Consumer Commission (**ACCC**) regulated transmission pipelines.

Schedule A of the gas code designated specific pipelines as either transmission or distribution. AGL's northern and southern trunks were classified as transmission pipelines.

The NSW legislation adopting the Gas Pipelines Law and a number of successive NSW savings regulations required that the trunk pipelines be treated as distribution pipelines for the purposes of that Law and the Code until the commencement of the NGL. Consequently, no elements of JGN's NSW network have been treated as transmission pipelines for the purpose of economic regulation.

On 22 April 2009, JGN applied to the National Competition Council (**NCC**) to reclassify its two trunk pipelines as distribution pipelines. On 29 June 2009, pursuant to section 129 of the NGL and in accordance with the NGR, the NCC reclassified the northern and southern trunk pipelines as distribution pipelines for the purposes of the NGL.

2.5 Service provider

Jemena Gas Networks (NSW) Ltd provides to users all services that are the subject of its AA.

In response to a November 2008 request from the AER, JGN considered whether any entity besides JGN was a service provider for the network. JGN took into account the definition of service provider in section 8(1) of the NGL and recent relevant court decisions. In particular, JGN considered whether JAM, JGN's contracted asset manager, is also a service provider.

JGN concluded that JGN is the only service provider in relation to the network. JGN is the only entity that does or will provide pipeline services to users by means of the JGN network. It is also the only entity that controls, owns and operates the network in terms of rule 8(1) of the NGL. JGN provided the AER with information to this effect.[10]

JGN is not a local agent of a service provider of the JGN network and does not act on behalf of another service provider of the JGN network.

2.6 Associate contracts

JGN is party to one associate contract concerning an interconnection of embedded network agreement and the novation of certain contractual responsibilities of Delta Electricity under that agreement to Jemena Colongra Pty Ltd (ACN 127 533 519) (**Jemena Colongra**). The associated contract, the Interconnection Side Deed, dated 25 March, 2008, partially novates (from Delta Electricity to Jemena Colongra) the terms and conditions under which JGN agrees to design, construct, operate and maintain the delivery station for interconnection with the Jemena Colongra pipeline. This is an associate contract as defined in the NGR as Jemena Limited owns both JGN and Jemena Colongra.

2.7 New external factors affecting JGN's business

There are two key external factors that are affecting, or about to affect, JGN's operations and associated costs, and that JGN has taken into account when preparing its revised AA:

- *Government policy measures in response to climate change* – The Australian Government has a stated intention to implement carbon pricing and trading, fugitive emissions reporting, and other new policies—such as renewable energy target and national hot water schemes

- *energy market developments and regulation* – Several new developments will come into effect after the submission date for JGN's revised AA: the national energy customer framework, the national gas connections framework, the short term trading market, and commencement of the AEMO.

2.7.1 Carbon trading

On 14 May 2009, the Australian Government introduced its Carbon Pollution Reduction Scheme (**CPRS**) Bill into Parliament. The second reading speech indicated that there will be a phased introduction to the scheme. Mandatory obligations would commence one year later than originally proposed, on 1 July 2011. Notwithstanding the 14 August 2009 defeat of the Government's CPRS legislation in the Federal Parliament, JGN understands this bill will shortly be

[10] Jemena Limited, Letter to AER, 30 January 2009.

reintroduced to the parliament. JGN has therefore relied upon the exposure draft for the purpose of this AAI.

While the impact of the CPRS is uncertain, it could affect JGN directly and indirectly:

- directly:
  - JGN has a carbon footprint and is therefore affected by the carbon price (e.g. fugitive emissions discussed below)
  - there is a need to ensure that contractual arrangements allow JGN to pass through the carbon cost
  - there will be new compliance costs under the CPRS.
- indirectly:
  - the CPRS will alter energy price relativities and this may, on balance, significantly reduce demand for natural gas
  - the effects of a carbon price will be reflected in network input costs – that is, the cost of goods and services which JGN uses to maintain its network (i.e. operating costs) or to augment and expand it (i.e. capital costs).

JGN has commissioned an expert report to address carbon price impacts on its input costs which is discussed further below and presented in Appendix 6.4.

JGN has also relied upon a report the National Electricity Market Management Company Limited (NEMMCO) commissioned to determine the forecast carbon certificate prices and wholesale gas prices during the next AA period. Table 2-2 sets out the forecasts JGN has adopted and the sources of these forecasts.

Table 2-2: Carbon credit forecasts

Uncertainty	Forecast		Basis of forecast
		$ per C02e	
CPRS – Government will introduce carbon price from 2011-12 using the following prices:	2010-11 2011-12 2012-13 2013-14 2014-15	0.00 9.54 26.14 28.09 30.04	Commonwealth Budget ACIL Tasman, *Fuel Resource, New Entry and Generation Costs in the NEM*, April 2009[11]
		$ per GJ	
CPRS – NSW wholesale gas price will be:	2010-11 2011-12 2012-13 2013-14 2014-15	5.54 5.50 5.48 5.49 5.51	ACIL Tasman, *Fuel Resource, New Entry and Generation Costs in the NEM*, April 2009

The above carbon credit forecasts have been used by JGN in compiling its demand forecasts in chapter 5 and in its opex forecasts in chapter 6.

Should circumstances change materially or new information come to light during the AA review period between the submission date and when the AER finally approves JGN's AA, JGN may revise these forecasts and resubmit them to the AER.

2.7.2 Fugitive emissions

The majority of JGN's fugitive emissions come from its distribution system. JGN, or an entity on behalf of JGN, will have to buy carbon permits to offset the carbon cost of fugitive emissions from this source.

The National Greenhouse and Energy Reporting laws (**NGER**) set the technical requirements for measuring carbon emissions that most likely will apply to emitters under the CPRS. Emitters must calculate emissions by source, including from gas transmission and distribution, vehicles, electricity and network contractors.

In gas transmission and distribution, fugitive emissions may result from compressor maintenance at compressor stations, maintenance on pipelines, gas leakage and accidents. Emissions for transmission and distribution will be treated differently under the NGER laws:

[11] www.nemmco.com.au

- *transmission pipe emissions* – pipelines with pressure greater than 1050 kPA are treated as transmission pipelines, with leakage calculated as a function of pipe length

- *distribution pipe emissions* – pipelines with pressure less than or equal to 1050 kPA are treated as distribution pipelines with leakage calculated as a function of throughput.

JGN has included the cost of UAG in its forecasts (see section 6.5.4) and is proposing a tariff variation mechanism for UAG which includes recovering the cost of these permits (see section 16.5.1).

2.7.3 Policies that influence end use

Several government policies are affecting the demand for gas that JGN distributes. Two of the most significant are the renewable energy target scheme and the national not water strategic framework.

Renewable energy target scheme

In 9 June 2009, the Australian Government released an exposure draft of the Renewable Energy (Electricity) Amendment Bill 2009 to expand the renewable energy target (**RET**) scheme by setting higher annual renewable energy targets beyond 2010.[12] The expanded scheme will provide that the equivalent of at least 20 per cent of Australia's electricity comes from renewable sources by 2020. The scheme will commence no later than 1 July 2011. The RET scheme has been designed in cooperation with the states and territories through the Council of Australian Governments (**COAG**) and brings the current renewable energy target (**MRET**) scheme and existing and proposed state schemes into a single national scheme.

An important initiative of the Bill for JGN is the creation of a solar credits mechanism based on a renewable energy certificate multiplier for small-scale renewable energy, including solar photovoltaic (**PV**), wind and micro-hydro systems.

JGN is particularly concerned with the continuing inclusion of solar and heat pump water heaters as eligible sources for the purpose of the MRET scheme and the negative impact of their inclusion on achieving Government's greenhouse gas and environmental objectives. These devices act not only as replacements for electric systems, where a reduction in emissions will result, but also as replacements for

[12] This account of the bill is extracted from Department of Climate Change, *Renewable Energy (Electricity) Amendment Bill 2009 - Exposure Draft, Commentary*, June 2009.

less carbon-intensive gas systems, which on balance will cause emissions to increase.

National hot water strategic framework

The Ministerial Council on Energy's (**MCE's**) national hot water strategic framework provides for the reduction of greenhouse gas emissions associated with water heating. It specifies minimum energy performance standards for water heaters and phasing out of conventional electric resistance water heaters, except where the emissions intensity of the public electricity supply is low, together with a range of information and education measures.[13]

The phase-out of conventional electric resistance water heaters is intended to cover all new homes and established homes in gas reticulated areas from 2010, and new flats and apartments in gas reticulated areas and established homes in gas non-reticulated areas from 2012.

While it might be expected that gas distribution businesses would be beneficiary of the new framework, the gains for gas are likely to limited by the operation of the RET scheme as described above. Where reticulated natural gas is available, particularly if it is already connected to the house, gas water heating is generally the lowest cost option. This cost advantage will be eroded by the combination of renewable energy certificate (**RECs**) attributable to electric solar hot water and heat pumps which are eligible sources for the purpose of the RET scheme, and state-based rebates—for example, the NSW Government offers $1,200 to households switching from electric to solar hot water.

2.7.4 Expert reports

JGN has commissioned or utilised a number of expert reports which deal with the effects on JGN of the CPRS and other energy policy initiatives over the next regulatory period. These are cited in appropriate sections and chapters of this AAI. The reports are noted in Table 2-3.

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[13] Ministerial Council on Energy, *Communiqué*, Adelaide, December 2008.

Table 2-3: Reports addressing effects of CPRS on JGN demand and cost forecasts

Report	Issues addressed
NIEIR, *Natural Gas Projections NSW, Jemena Gas Networks to 2019*: A report for Jemena Gas Networks (NSW) (April 2009[14]	• gas prices and the CPRS • renewable energy target • mandatory energy performance standards • other Commonwealth and NSW initiatives (Appendix 5.1 of this AAI summarises the NIEIR report's description of the above matters)
CEG, *Escalation factors affecting expenditure forecasts*: A report for Jemena Gas Networks, June 2009[15]	The effect of carbon trading on the prices of material inputs into JGN expenditure programs
ACIL Tasman, *Fuel Resource, New Entry and Generation Costs in the NEM*, April 2009	• forecast wholesale gas prices • forecast carbon certificate prices

2.7.5 Energy market and regulatory developments

A number of developments in the energy market and regulation will be finalised and come into effect after the submission date for JGN's revised AA:

- *national energy customer framework* (**NECF**) – that will mandate a standard distribution contract for small network customers. a retail support contract between distributors and retailers, and establish a new liability regime for distributor obligations towards small customers and retailers

- *national gas connections framework* (**NGCF**) – part of a wider customer connections framework that will standardise many of the contracts for connecting customers to electricity and gas networks, including JGN's network

- *AEMO* – has commenced as the body now responsible for the market operations previously undertaken by the NEMMCO, Victorian Energy Networks Corporation (**VENCorp**), the Retail Energy Market Company, and the Gas Market Company under the current market rules and procedures, which may be consolidated in due course

[14] Appendix 5.2.
[15] Appendix 6.5.

- *short term trading market* (**STTM**) – that will facilitate settlement of wholesale gas sales to JGN's trunk and distribution assets servicing Sydney, Wollongong, Newcastle and the Central Coast, and will treat them as a single market hub.

It is not yet possible at this stage to determine the impact that these developments will have on costs over the next AA period. Accordingly JGN has proposed pass through arrangements to address uncertainties and these arrangements are set out in section 16.6.

The trading principles behind the STTM are reasonably well understood and this provides JGN an opportunity to propose changes to its access arrangement that can enhance the market's success:

- *tariff restructuring* - section 13.6 discusses how JGN has restructured its tariffs for demand customers to accommodate the STTM nomination and balancing mechanism

- *removal of zonal pricing across the trunk pipelines* – section 8.5 explains how JGN has treated its trunk asset base to accommodate the STTM assumption that the JGN network is unconstrained.

2.8 RIN and rule 72 requirements

Table 2-4 below sets out RIN requirements met in chapter 2. There are no rule 72 requirements met in chapter 2.

Table 2-4: Summary of RIN responses

RIN reference	RIN requirement	Where addressed in AAI
Local agent of a service provider		
2.1.2	In the access arrangement proposal submission, provide a statement that the service provider in 2.1.1 is not a local agent (of a service provider of the pipeline)	Section 2.5
Service provider acting on behalf of other service providers		
2.1.3	In the access arrangement proposal submission, provide a statement that the service provider in 2.1.1 is not acting on behalf of another service provider of the pipeline.	Section 2.5

RIN reference	RIN requirement	Where addressed in AAI
Associate contracts		
2.1.4	For each associate contract relevant to the delivery of pipeline services provide in the access arrangement proposal submission: (a) The name of the associate contract (b) The name of all parties to the associate contract (c) An outline of the nature of goods or services provided by or obtained from the associate contract (d) An outline of the relationship of party or parties to the associate contract to each service provider of the pipeline. Maintain: (e) The associate contracts at service provider's premises identified in section 2.1.1 of this notice for all associate contracts identified in 2.1.4(a) of this notice	Section 2.6 See also section 3.3

3 Delivery of JGN activities

JGN has established a prudent mix of in-house functions and outsourced activities. The delineation between these activities reflects JGN's selective retention of commercial and governance functions, while adopting outsourcing for activities where contracted asset managers can achieve economies of scale and scope that are not available to JGN on a stand-alone basis.

This chapter describes the structure of JGN's operations, its choice to outsource activities, and its recent renegotiation of the terms and conditions of those outsourced services.

The chapter is structured as follows:

- *Section 3.1 Summary* – provides an overview of JGN's in-house and outsourced activities
- *Section 3.2 Structure of JGN management* – describes how Jemena's Infrastructure Investments division manages JGN's business activities
- *Section 3.3 Asset Management Agreement* – provides the AMA between JGN and Jemena Asset Management, including the scope of services, how the contract was awarded, the governance and risk sharing arrangements, the contract term, pricing and incentive provisions
- *Section 3.4 RIN and rule 72 requirements* – maps the RIN and NGR rule 72 requirements to the relevant sections, chapters and regulatory models.

3.1 Summary

The Infrastructure Investments division manages an extensive range of business activities. Their objective is to optimise JGN's commercial position and enable it to respond effectively to its market and regulatory incentives. These activities include business planning and governance and the management of financial, regulatory management, capital investment, market, commercial and technical aspects of JGN. In addition Jemena Limited's corporate divisions provide enterprise support functions (**ESFs**) to support the management of JGN's business.

JGN outsources delivery of its capital program and its operating and maintenance (**O&M**) activities to JAM. Prior to current AMA arrangements, JGN conducted this outsourcing under arrangements that were in place under the former AGL ownership.

During 2009, JGN's management conducted a service model project. The objective of the project was to establish a formal asset management agreement (**AMA**) under which JGN can continue to procure asset management services at an efficient level of cost and with incentives aligned to ensure ongoing service and cost performance.

JGN initiated bilateral negotiations with JAM to develop their new AMA. The negotiation framework followed standard commercial practices for competitively tendering work. The resultant agreement, which came into effect from 1 August 2009, creates a number of valuable outcomes for JGN:

- services and accountabilities are clearly defined
- costs are transparent
- strong incentives to ensure JAM delivers JGN's required services at the lowest sustainable cost
- risk is allocated to the party that can best manage it
- JGN has certainty of asset management resourcing at least until the end of 2018.

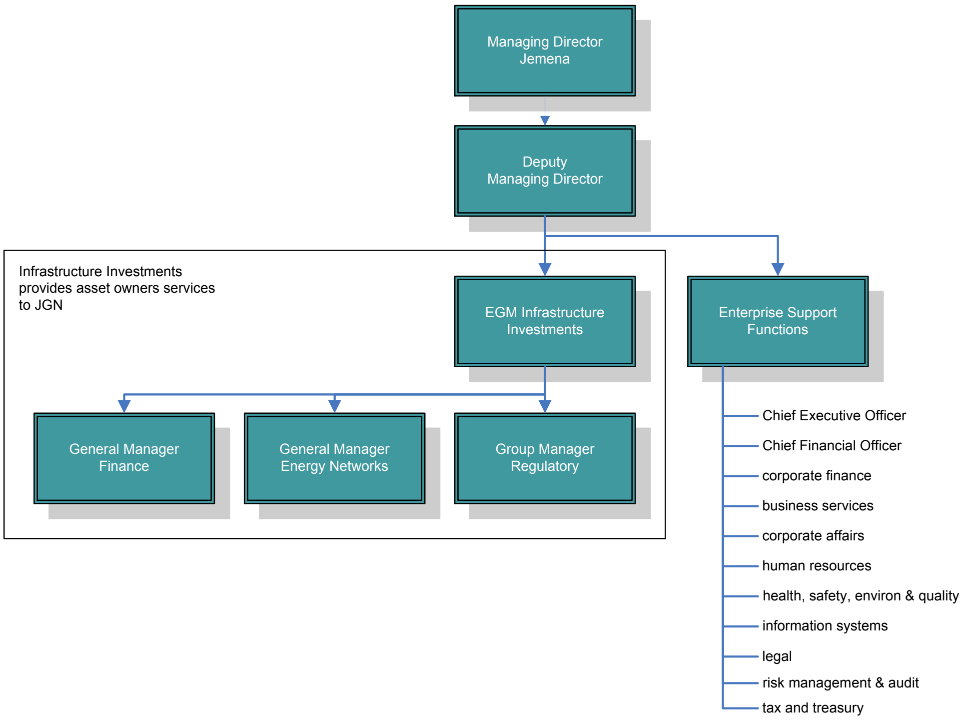
3.2 Structure of JGN management

As indicated in section 2.3, Jemena Limited owns 100 per cent of JGN. Jemena Limited is part of the group owned by SPI (Australia) Assets Pty Ltd (**SPIAA**), which is not publicly listed on the Australian Stock Exchange.

Within Jemena Limited, the Infrastructure Investments division manages JGN's business. In addition Jemena Limited's corporate divisions provide ESFs to support the management of JGN's business.

Figure 3-1 shows the management structure of JGN.

Figure 3-1: JGN management structure



Through this structure, the Infrastructure Investments division manages an extensive range of business activities, the scope of which is summarised in Table 3-1. Their objective is to optimise JGN's commercial position and enable it to respond effectively to its market drivers and regulatory incentives.

Table 3-1: Scope of management activities

Activity	Description
Business planning and governance	• developing strategic asset plans • developing of business plans and budgets • overseeing JGN's financial, commercial and technical activities
Financial management	• establishing accounting policy and procedures • reporting and forecasting financial, commercial and technical performance of the network businesses • validating cost reporting and payments • maintaining JGN's accounts
Regulatory management	• managing issues and relationships with government, regulators and market operators • managing access arrangement reviews • ensuring compliance

Activity	Description
Capital management	• identifying the scope of capital works (both growth and maintenance) required to meet JGN's growth and system performance objectives • developing arrangements to source these works at least cost • ensuring all network capex passes regulatory tests of effectiveness and efficiency
Market management	• developing and implementing network market development strategies to deliver: – retention of existing customers – increased network utilisation by existing customers – adoption of new products – new connections – footprint expansion opportunities
Commercial management	• establishing commercial policies, procedures and controls • developing and managing transportation contracts • developing transportation pricing offers to retailers and major customers • managing relationships and negotiations with retailers and major end consumers and other industry participants • ensuring performance of JGN's contractual and market obligations • ensuring the integrity of IT systems and business processes used in metering and billing of network services
Technical management	• establishing network asset performance objectives and targets • establishing frameworks and policies for management of technical risk • approving asset management plans • establishing and managing contracts for the delivery of asset management, O&M and construction services • monitoring the performance of service providers in delivery of services
Enterprise support functions	• CEO – executive oversight and board liaison • CFO – executive oversight • corporate finance • business services • corporate affairs • human resources • health, safety, environment and quality • information systems • legal • risk management & audit • tax and treasury

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3.3.2 Basis of JGN's new outsourcing

During 2009, JGN's management conducted a service model project. The objective of the project was to establish a formal asset management agreement (**AMA**) under which JGN can continue to procure asset management services at an efficient level of cost and with incentives aligned to ensure ongoing service and cost performance.

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3.4 RIN and rule 72 requirements

Table 3-4 sets out RIN requirements met in chapter 3. There are no rule 72 requirements in chapter 3.

Table 3-4: Summary of RIN responses

RIN reference	RIN requirement	Where addressed in AAI
Outsourced expenditure (overlap with chapter 10)		
2.3.5.4	For opex that is material to an opex category and forecast to be incurred in the access arrangement period but provided by a party other than the service providers (i.e. outsourced) provide in the access arrangement proposal submission	
	(a) The name of the external party or parties and contract	Section 3.1
	(b) Details of how the contract was awarded (for example, by competitive tender)	Section 3.3.4
	(c) Details of fees and charges and a description of the goods or services provided	Section 3.3.9 and 3.3.3

RIN reference	RIN requirement	Where addressed in AAI
	(d) The commencement date and term of the contract	Section 3.3.7
	(e) Reasons why the functions were outsourced	Section 3.3.2
	(f) Details of the relationships with the party or parties named in 2.3.5.4(a) including if a party to the contract is an associate of any of the service providers of the pipeline	Section 3.3
	(g) Define the materiality threshold used	JGN has defined its materiality threshold as 10 per cent of a given operating cost category.

Part 2 – JGN cost of service

Part 2 provides details of the JGN building block components that make up its cost of service.

4 Current performance

To assist the AER in assessing JGN's AA, the RIN seeks information on past performance. This chapter examines JGN's performance during the current AA period in the areas of:

- demand, energy consumption and customer numbers
- opex
- capex
- key performance indicators (**KPIs**).

This chapter is structured as follows:

- *Section 4.1 Summary* – provides a summary of JGN's performance in the current AA period
- *Section 4.2 Customer numbers, demand and volume* – discusses JGN's demand, energy and customer numbers performance in the current AA period
- *Section 4.3 Operating expenditure* – examines JGN's opex performance
- *Section 4.4 Capital expenditure* – considers JGN's capex performance
- *Section 4.5 Key performance indicators* – sets out JGN's performance in terms of its KPIs
- *Section 4.6 RIN and rule 72 requirements* – maps the RIN and NGR rule 72 requirements to the relevant sections in this chapter.

4.1 Summary

In the current AA period, JGN continues to manage its network effectively, as demonstrated by sound network performance outcomes for customers, and delivery of significantly enhanced capital and operating investment programs.

Over the current AA period:

- JGN's actual and estimated gas loads and customer numbers have been lower than IPART forecast and used to determine JGN's prices in 2005
- JGN has achieved operating cost efficiencies greater than those IPART forecast in its 2005 decision
- JGN has met its commitment to invest in capital works that extend the life and capacity of its network, and to maintain reliability using innovative solutions, many designed to defer more major reinforcements and contain expenditure within the regulatory alowance.

JGN expects to incur operating expenditure over the current period of $633.7 million, which is 7.34 per cent below that allowed by IPART.

Over the current period, JGN expects to invest $556.6 million, which is within 1.21 per cent of the amount IPART allowed in 2005.

4.2 Customer numbers, demand and volume

Table 4-1 to Table 4-4 provide a series of JGN's outcomes over the current AA period in relation to customer numbers, maximum, minimum and average demand, and total gas load (volume). Maximum daily quantity (**MDQ**) for large customers is also shown.

Table 4-1: Customer numbers during the current AA period

Customer numbers by type	2005-06 actual	2006-07 actual	2007-08 actual	2008-09 forecast	2009-10 forecast
Residential	945,257	965,653	995,074	1,017,157	1,043,653
Small business	29,293	30,683	30,869	30,721	30,869
Total volume customers	**974,550**	**996,336**	**1,025,943**	**1,047,878**	**1,074,522**
Demand customers	483	444	430	421	423
Total customers	**975,033**	**996,780**	**1,026,373**	**1,048,299**	**1,074,945**

Table 4-2: Minimum, maximum and average daily load total JGN network 2005-06 to 2007-08 (TJ)

	2005-06 actual	2006-07 actual	2007-08 actual
Minimum load	130.2	149.4	132.8
Maximum load	391.5	399.2	415.8
Average daily load	259.7	266.7	271.2

Note. JGN does not have available forecasts of maximum and minimum total system wide demand, which is why the above table provides historical data.

Table 4-3: Average daily gas load - volume and demand customers and MDQ for demand customers for current AA period (TJ)

	2005-06 actual	2006-07 actual	2007-08 actual	2008-09 forecast	2009-10 forecast
Volume customers	87.1	89	91.9	96.2	89.1
Demand customers	172.6	177.7	179.3	179.7	166.3
Total average daily load	259.7	266.7	271.2	275.9	255.3
MDQ for demand customers	292.5	295.1	293.3	334.2	317.5

Note:

1. Average daily gas loads derived from totals in Table 4-4**.**
2. Demand customer MDQ for 2005-06 to 2007-08 is booked MDQ. Remaining years are NIEIR MDQ forecast adjusted for a large new customer. See section 5.9.2 of this AAI.

Table 4-4: Gas load by customer type and tariff for current AA period (TJ)

Service	2005-06 actual	2006-07 actual	2007-08 actual	2008-09 estimated	2009-10 estimated
Residential	20,010	20,649	21,327	22,875	20,438
Small business	11,790	11,843	12,210	12,227	12,072
Total volume customers	**31,800**	**32,492**	**33,537**	**35,102**	**32,510**
Total demand customers	62,988	64,857	65,452	65,597	60,690
Total load all customers	**94,788**	**97,349**	**98,989**	**100,699**	**93,200**

Note:

1. Gas loads for 2008-09 are actual/estimated billed numbers obtained from table 4.2 in the NIEIR report with demand customer load adjusted for a large new customer.
2. 2009-10 gas loads are NIEIR weather normalised forecasts as adjusted in Section 5.9 of this AAI (Table 5-11).

When appropriate adjustments are made to ensure like-with-like comparisons, it can be seen that JGN's market did not attain the levels IPART forecast in 2005 and used to determine JGN's prices. Consequently, JGN has under-recovered its revenue by a considerable amount over the current AA period.

JGN provides some comparisons below.

Various factors have contributed to lower than forecast residential load. These factors include lower than forecast new connections, competition from alternate energy applications particularly reverse cycle air conditioning and solar/heat-pump hot water systems, and improved levels of energy efficiency for residential gas appliances.

Figure 4-1 shows the relative demand outcomes:

Figure 4-1: JGN NSW gas load all customers

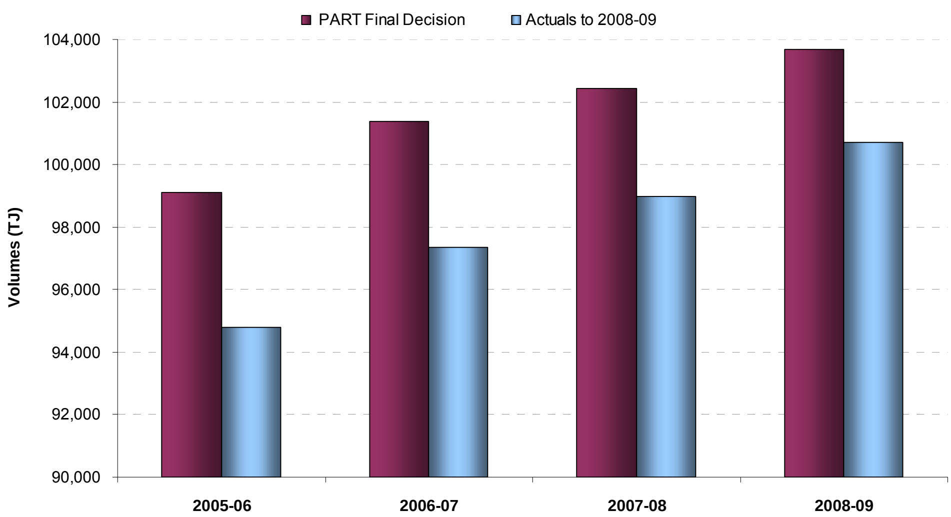


Table 4-5: Forecasts of total gas load compared with actual (TJ)

Forecast	2005-06	2006-07	2007-08	2008-09
IPART final decision – Apr 2005	99,107	101,373	102,432	103,694
AGLGN's submission – Dec 2003	98,690	100,769	101,560	102,561
Actuals to 2007-08 plus estimate 2008-09	94,788	97,349	98,989	100,699

JGN notes that the total customer load over the current AA period is closer to the forecasts AGLGN submitted to IPART in 2003.[17]

[17] AGL Gas Networks Limited, *Access Arrangement Information for NSW Network*, December 2003, pp. 8-15.

The effect of the IPART final decision on JGN's revenue is further demonstrated by the comparison for volume customers shown in Table 4-6 below. This is because most of JGN's revenue is derived from this sector and any significant shortfall in volume demand will have major impacts on revenue.

Table 4-6: Forecasts of volume customers' gas load compared with actual and current estimates (TJ)

Forecast	2005-06	2006-07	2007-08	2008-09	2009-10	Total
IPART final decision - Apr 2005	34,107	35,135	36,202	37,325	38,469	181,238
Actuals to 2007-08, estimates for 2008-09 and forecast for 2009-10	31,071	32,554	33,743	33,173	32,510	163,051
Variance	3,036	2,581	2,459	4,152	5,959	18,187

Note: Actual gas load for 2005-06 to 2007-08 in this table has been weather normalised.

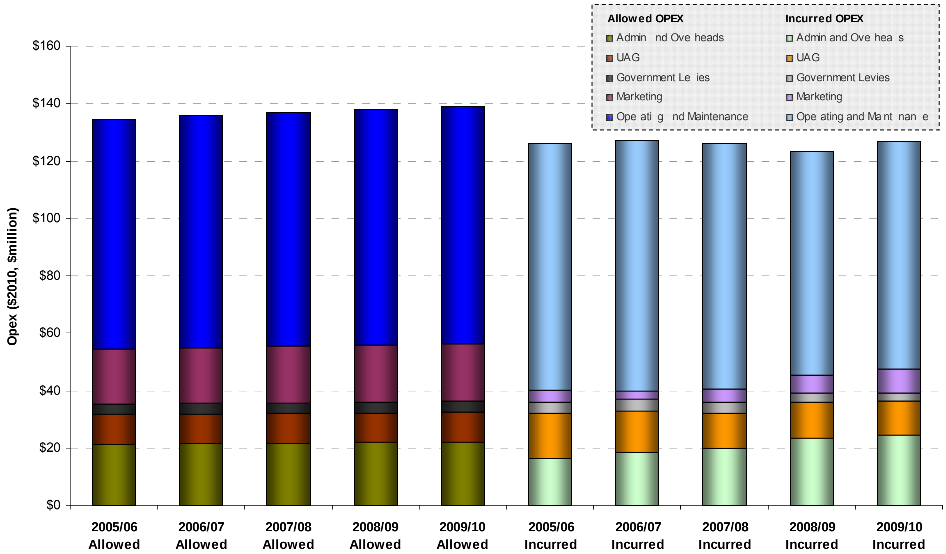
The volume customer load is below the IPART final decision by 18 petajoules over the current AA period, or 10 per cent. This is a significant shortfall and has resulted in a revenue shortfall of about eight per cent over the current AA period relative to the IPART approved cost of service.

JGN's experience in the last AA review shows how important policy measures can be in their impact on gas load, and how necessary it is to factor them into demand forecasts. Failure to give appropriate recognition to all significant market factors and policy measures can result in inaccurate forecasts, effectively denying the service provider an opportunity to recover at least its efficient costs.

4.3 Operating expenditure

Figure 4-2 shows the opex forecast that IPART allowed for JGN (AGLGN) in the 2005 final decision, in the categories that IPART specified. At a total opex level, JGN expects to incur operating expenditure over the current period of $633.7 million, which is $50.18 million (or 7.34 per cent) below that allowed.

Figure 4-2: JGN historic opex ($2010)



JGN recognises the RIN requirement (following rule 72(1)(a)(ii)) that the AAI provides actual opex (by category) over the earlier AA period. JGN has sought to represent its historic cost information in this manner (see Table 4-7). However, JGN notes that some minor categories of expenditure present issues when comparing the IPART opex categories with the actual outcome for the years 2005-06 to 2007-08 and similarly forecasts for years 2008-09 and 2009-10.

In particular, some of cost categories were new obligations (or step changes) at the time of the 2005 final decision. Since then, these activities have become part of JGN's general operating costs: they have not been recorded separately over the current AA period. For example, retail contestability costs were determined by IPART to be uncontrollable costs, but now form part of JGN's O&M costs.

Notwithstanding these categorisation differences, the outturn costs for JGN over the current AA period have been developed as shown in Table 4-7, and compared with the IPART approved costs.

For these reasons, comparing the allowed/incurred outcomes for individual cost categories is problematic, and it is more accurate to focus on the total outcomes over the current AA period.

Table 4-7: Allowed non-capital costs compared with actuals and JGN's currently estimated and forecast outcomes

Cost category		2005-06	2006-07	2007-08	2008-09	2009-10
Operating and maintenance	Allowed	79.8	80.9	81.5	82.1	82.7
	Incurred	85.9	87.2	85.4	77.9	79.4
Administration and overheads	Allowed	21.2	21.5	21.7	21.9	22.1
	Incurred	18.4	20.3	20.8	24.0	24.5
Marketing	Allowed	19.2	19.5	19.6	19.8	20.0
	Incurred	4.3	2.8	4.6	6.5	7.5
Government levies	Allowed	3.7	3.7	3.7	3.7	3.7
	Incurred	3.8	4.3	4.0	3.1	3.1
UAG	Allowed	10.5	10.3	10.4	10.4	10.5
	Incurred	15.7	14.1	12.0	12.5	11.6
Total non-capital costs	**Allowed**	**134.4**	**135.8**	**136.9**	**137.8**	**138.9**
	Incurred	**128.1**	**128.6**	**126.8**	**124.0**	**126.2**
Efficiencies achieved (per cent)		***6.4***	***7.2***	***10.0***	***13.8***	***12.8***

Notes:

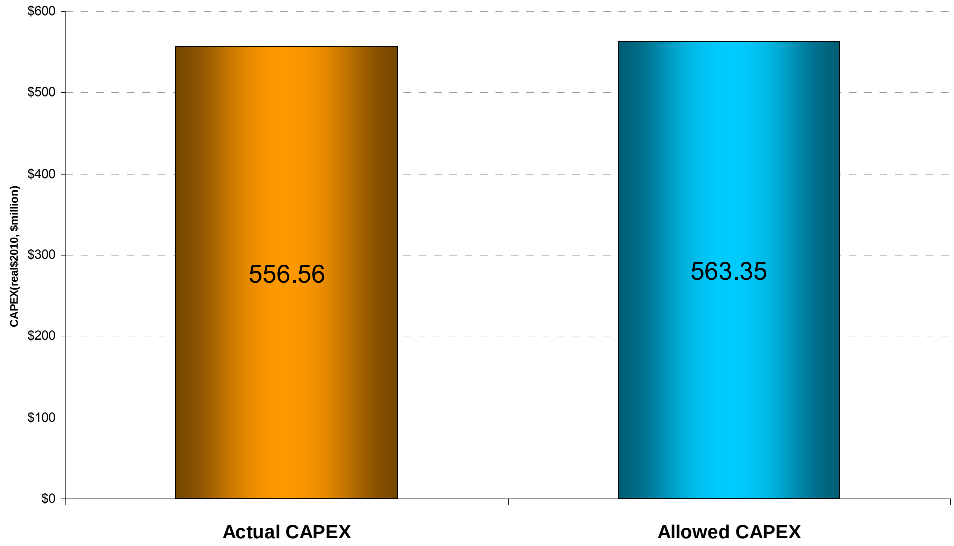
1. Amounts allowed are adapted from IPART Final Decision, *Revised Access Arrangement for AGL Gas Networks*, April 2005, Table 5.1.
2. Amounts incurred are JGN's actuals to 2007-08, its estimates for 2008-09, and its forecast for 2009-10.
3. O&M costs include retail contestability and market operations.
4. The O&M costs that JGN incurred from 2005-06 to 2007-08 were the agreed fee that JGN paid to JAM under its previous outsourcing arrangements. The O&M costs that JGN expects to incur in 2008-09 and 2009-10 are based on JGN's new outsourcing agreement with JAM.

4.4 Capital expenditure

Over the current AA period, JGN has spent most of its allowed capex.

Figure 4-3 illustrates JGN's capex spend compared to the IPART allowance. It shows that total capex for JGN is projected to be $556.56 million over the current AA period, representing a total expenditure that is $6.79 million, or approximately 1.21 per cent, below the level allowed by IPART in 2005.

Figure 4-3: Comparison of JGN's actual capex to allowance



JGN's capex is split into the following categories:

- *market expansion*—new assets required for the connection of new customers, including new mains, services and meters
- *system reinforcement*—enhancements to the system to maintain capacity for existing customers and provide capacity for future market expansion activities, including renewal and upgrade of assets that are reaching the end of their lives such as mains and services rehabilitation and aged meters.
- *non-system assets*—IT systems and software, motor vehicles, plant and equipment which are not part of the network.

JGN's actual capex generally has been in line with allowance and any divergence is explained below. For example, JGN has successfully delivered the Sydney Primary Loop project foreshadowed in its last AA. This highlights JGN's commitment to delivering on major capital works projects.

JGN considers that its actual capex satisfies the conforming capital test under rule 79 and, by inference, the equivalent test under section 8.16(a) of the former gas code. This view is supported by the Parsons Brinckerhoff (**PB**) report for network capex and the KPMG report for IT capex. These reports are provided in appendix 7.4 and appendix 7.5 respectively.

JGN proposes using this actual capex to establish the opening RAB for the next regulatory period as discussed in chapter 8.

IPART's final decision allowed $563.4 million of capex over the current AA period which JGN was required to use include in the roll-forward its regulatory asset base to 30 June 2010.[18]

As shown in Table 4-8, JGN expects to incur capex over the current AA period of $556.6 million, which is $6.8 million (1.21 per cent) below that allowed by IPART in 2005.

Table 4-8: Allowed capital costs compared with actuals and JGN's currently estimated and forecast outcomes

Cost category		2005-06	2006-07	2007-08	2008-09	2009-10	Total
Market expansion	Allowed	63.2	62.1	60.8	61.1	61.6	308.8
	Incurred	49.7	40.4	41.9	48.9	53.9	234.8
System reinforcement / renewal / replacement	Allowed	69.1	46.4	43.1	26.8	19.7	205.1
	Incurred	47.7	90.7	46.7	39.6	47.8	272.5
Non-system assets	Allowed	9.2	9.2	9.2	10.6	11.2	49.5
	Incurred	2.2	0.7	19.7	12.8	13.9	49.3
Total capital costs	**Allowed**	**141.5**	**117.7**	**113.2**	**98.5**	**92.5**	**563.4**
	Incurred	**99.6**	**131.7**	**108.3**	**101.3**	**115.6**	**556.6**
Variance (per cent)		**-29.6**	**11.9**	**-4.3**	**2.8**	**25.0**	**-1.2**

Notes:

1. Amounts allowed are adapted from IPART Final Decision, *Revised Access Arrangement for AGL Gas Networks*, April 2005, Table 7.7.
2. Amounts incurred are JGN's actuals to 2007-08, estimates for 2008-09, and forecast for 2009-10.

To comply with the AER's AA consolidation and RIN requirements, Appendix 7.3 further categorises this expenditure into major pipelines and asset categories.

Table 4-9 explains the variation between JGN's actual capex to that allowed by IPART for each program over 2005-06 to 2008-09.

JGN has engaged PB to provide an independent expert review of whether its historic capex spend complies with the conforming capital criteria of the NGR. PB's report, which concludes that JGN's historic capex is compliant, is provided in Appendix 7.4. In its report PB notes that:

[18] IPART Final Decision, *Revised Access Arrangement for AGL Gas Networks*, April 2005, Amendments 9 and 10.

PB considers that rule 79 is equivalent if not more onerous than the equivalent section, 8.16(a), of the gas code. Therefore it is reasonable to infer that if capex meets rule 79 it meets the code equivalent. [19]

Table 4-9: Analysis of variance between allowed and actual capex over 2005-06 to 2008-09

Capex category	Analysis of variance
Market expansion	There was a substantially lower number of new customer connections than forecast.
System reinforcement/renewal/ replacement	JGN experienced higher than forecast expenditure on: • replacement and renewal of aging high pressure facilities • the Primary Loop security of supply project • mine subsidence mitigation projects • upgrade of high pressure facilities required by MSP pressure upgrade This was partially offset by lower expenditure on system reinforcement projects due to substantially lower utilisation of the network than forecast and the deployment of innovative technology (low differential pressure district regulators) to increase capacity of existing system and defer reinforcement requirements.
Non-system assets	There was no material variance.

4.5 JGN's key performance indicators

JGN's current AA contains a number of KPIs for opex. This section sets out JGN's current performance as well as its proposed KPIs for the next AA period.

4.5.1 Current AA period

In the revised 2005 AAI submitted to IPART, JGN included a number of forecast KPIs for the current AA period. Separate KPIs (in 2005 dollars) were provided for the trunk and distribution segments of the network. These KPIs have been updated to show actual figures for the years to 2008-09 and a forecast for 2009-10, both in 2010 dollars. The KPIs are set out in Table 4-10.

Table 4-10: Trunk segment KPIs: Operating cost per kilometre ($)

	2005-06	2006-07	2007-08	2008-09	2009-10
Wilton - Newcastle trunk	11,529	11,880	11,746	11,262	11,490
Wilton - Wollongong trunk	12,165	12,536	12,394	11,956	12,199

[19] Parsons Brinckerhoff Australia Pty Ltd, *2010-11 to 2014-15 Jemena Gas Networks Access ArrangementRreview – Review of JGN Capital Expenditure*, August 2009, p. 4, Appendix 7.4.

It is always important that any comparison of KPIs between one service provider and another take proper account of the differences in their markets and networks.

Table 4-11: Distribution segment KPIs: Operating cost per metre and cost per customer site ($)

	2005-06	2006-07	2007-08	2008-09	2009-10
Operating cost per metre	4.43	4.49	4.44	4.21	4.26
Operating cost per customer site	106.94	107.79	103.50	97.16	96.67

JGN has calculated operating cost per km and per metre by dividing the 'operating and maintenance' and 'administrative and overhead' costs for each pipeline segment by the relevant length of pipeline.

Operating cost per customer site for the distribution segment was based on the total operating cost allocated to the distribution system.

4.6 RIN and rule 72 requirements

Table 4-12 sets out RIN and rule 72 requirements met in chapter 4.

Table 4-12: Summary of RIN responses

RIN/rule 72 reference	RIN requirement	Where addressed in AAI
Demand in earlier access arrangement period		
RIN 2.2.2 Rule 72(1)(a)(iii)	(a) Provide in pro forma 11 minimum, maximum and average demand for the earlier access arrangement period and forecast maximum and average demand for the access arrangement period	Table 4-2 and pricing model Supporting information in section 4.2 for actual and section 5.9.4 for forecast Note: JGN does not have available forecasts of maximum and minimum total system wide demand.
	(b) Provide in pro forma 12 actual and estimated volumes for the earlier access arrangement period and forecast volumes for the access arrangement period by tariff class and pipeline service	Table 4-4, Table 5-3 and pricing model Supporting information in section 4.2 for actual and section 5.9.4 for forecast

RIN/rule 72 reference	RIN requirement	Where addressed in AAI
	(c) Provide in pro forma 10 actual and estimated customer numbers for the earlier access arrangement period and forecast customer numbers for the access arrangement period by tariff class and pipeline service	Table 4-1, Table 5-1 and pricing model Supporting information in section 4.2 for actual and section 5.9.4 for forecast
	(g) An explanation of any trends of demand and volumes over the earlier access arrangement period and access arrangement period	Section 4.2 for actual trends. Sections 5.6 and 5.8 for forecast trends. NIEIR report at Appendix 5.2
Opex in the earlier AA period		
RIN 2.3.5.1 Rule 72(1)(a)(ii)	Provide in pro forma 6 actuals and estimates of opex by category for each year of the earlier AA period	Table 4-7 and forecast data model Supporting information in section 4.3 for actual and sections 6.1, 6.5 and 7.6 for forecast
Capex in the earlier AA period		
RIN 2.3.1.2 Rule 72(1)(a)(i)	(a) Provide in the access arrangement proposal submission an explanation for: (i) any significant variations between capex approved by the jurisdictional regulator and the actual and/or estimated capex for the earlier access arrangement period (ii) how conforming capex added to the capital base in the earlier access arrangement period meets the code requirements.	Section 4.4 See also Appendix 7.4: PB review of AMP capex
	(b) Provide in pro forma 1 by asset class for each year of the earlier access arrangement period (i) Amounts added to the opening capital base for conforming capex (ii) Amounts for non conforming capex identified as recovered by surcharge, added to a speculative capex investment account (under the code a speculative investment fund), other amounts of non conforming expenditure.	Appendix 7.3 and regulatory asset base roll forward model

5 Demand forecasts

This chapter sets out JGN's forecast customer numbers, minimum and maximum demand, and volume for the next AA period.

The demand forecasts and customer numbers underpin JGN's forecast opex in chapter 6 and capex in chapter 7. The energy consumption and customer number forecasts are also a key input to calculating the X factors in the AER's post tax revenue model set out in section 13.8.

This chapter is structured as follows:

- *Section 5.1 Summary* – summarises JGN's customer numbers, demand and volume forecasts
- *Section 5.2 Law and rules requirements* – sets out the Law and rules requirements with which JGN's forecast must comply
- *Section 5.3 Summary of forecast demand* – provides a summary of JGN's demand forecasts
- *Section 5.4 Basis of demand forecasts* – explains the manner in which JGN has established its demand forecasts
- *Section 5.5 NIEIR demand forecast approach* – outlines the approach JGN's expert demand forecasters have applied to forecasts JGN's demand
- *Section 5.6 Overview of forecast results* – sets out the NIEIR forecast by customer category
- *Section 5.7 NIEIR methodological approach* – details the methodological approach used to establish forecasts
- *Section 5.8 Factors affecting load forecasts* – looks at key factors that affect the trends in JGN's demand forecasts over the next AA period
- *Section 5.9 JGN final forecasts and adjustments* – documents the adjustments JGN has applied to the NIEIR forecasts to arrive at its final demand forecasts over the next AA period
- *Section 5.10 Use of demand forecasts in JGN AAI* – identifies how and where JGN has relied upon these demand forecasts in its AAI

- *Section 5.11 RIN and rule 72 requirements* – maps the RIN and NGR rule 72 requirements to the relevant sections, chapters and regulatory models.

5.1 Summary

JGN operates its network in a temperate climate with a gas penetration rate significantly less than that of networks located in cooler climates. As a discretionary energy source, demand in JGN's area is highly weather and policy sensitive.

In this context JGN has sought to forecast gas demand including customer connections, gas consumption and volume customer maximum demand. In summary, JGN forecasts that:

- customer numbers will increase from 1.1 million in 2010-11 to 1.3 million in 2014-15, representing annual growth of 3.2 per cent over the next AA period
- maximum daily load for demand customers will decrease from 327.9 TJ in 2010-11 to 326.0 TJ in 2014-15, representing annual reduction of 0.1 per cent over the next AA period
- total gas load will increase from 96.02 PJ in 2010-11 to 97.7 PJ in 2014-15, representing annual growth of 0.4 per cent over the next AA period
- total gas load for volume customers will increase from 32.4 PJ in 2010-11 to 34.8 PJ in 2015-15, representing annual growth of 1.8 per cent.

JGN considers that the forecasts presented in this chapter are the best available and have been prepared on a reasonable basis in accordance with rule 74(2).

Total annual load on the JGN network is approximately 100 PJ, comprising 65 PJ of demand customer load (large customers) and 35 PJ of volume customer load (small customers).

JGN's forecast customer numbers, demand and volume over the next AA period is influenced by the following factors:

- Over the past five years demand customer load has been relatively steady, while volume customer load has grown at a modest 1.5 per cent. This is substantially lower than the actual growth in customer numbers of approximately 2.4 per cent and historical growth rates prior to 2000. This has resulted in a steady decline in average consumption per customer.
- Changes in consumer behaviour and improvements in gas appliance efficiency over the current AA period have resulted in significant reductions in average residential gas consumption in NSW.

- New dwelling construction is forecast to remain reasonably strong; however, the fall in consumption by existing connected households will substantially reduce growth in small customer gas volumes.

- The external factors, such as those discussed in chapter 2, contribute to forecast lower residential gas usage including:

  - the CPRS effect on gas prices

  - the renewable energy target

  - the mandatory energy performance standards

  - other Commonwealth and NSW initiatives.

- The current economic downturn is forecast to significantly increase small business closures, and therefore affect the growth in small business sector gas volumes.

Amid these conditions, JGN (through its expert NIEIR) has provided comprehensive demand forecasts that attempt to incorporate these key drivers. JGN's forecasts of its customer numbers, demand and volume have been prepared independently, and in accordance with the NGL and NGR.

5.2 Law and rules requirements

The national gas objective and the NGR s.74 requirements for forecasts and estimates noted in chapter 1 Table 1-1 of this AAI are applicable to JGN demand forecasts.

5.3 Summary forecast demand

Table 5-1, Table 5-2 and Table 5-3 set out JGN's forecast customer numbers, minimum and maximum demand, and volume over the next AA period respectively.

Table 5-1: Forecast customer numbers by type and tariff class for next AA period

	2010-11 Forecast	2011-12 Forecast	2012-13 Forecast	2013-14 Forecast	2014-15 Forecast
Residential	1,076,880	1,115,666	1,156,343	1,191,645	1,222,988
Small business	30,876	31,083	31,492	32,110	32,677
Total small customers	**1,107,756**	**1,146,749**	**1,187,836**	**1,223,755**	**1,255,664**
Large customers	424	424	424	425	426
Total customers	**1,108,180**	**1,147,173**	**1,188,260**	**1,224,180**	**1,256,090**

Table 5-2: Average load volume and demand customers next AA period and MDQ demand customers (TJ)

	2010-11 Forecast	2011-12 Forecast	2012-13 Forecast	2013-14 Forecast	2014-15 Forecast
Volume customers	88.9	89.0	90.9	93.2	95.3
Demand customers	174.2	175.8	171.4	172.1	172.4
Total average load	**263.1**	**264.7**	**262.3**	**265.3**	**267.7**
MDQ demand customers	327.9	330.7	325.0	325.9	326.0

Table 5-3: Load by customer type and tariff for next AA period (TJ)

Service	2010-11 Forecast	2011-12 Forecast	2012-13 Forecast	2013-14 Forecast	2014-15 Forecast
Residential	20,475	20,513	21,059	21,558	21,992
Small business	11,961	11,966	12,128	12,451	12,777
Total load volume customers	**32,435**	**32,480**	**33,187**	**34,010**	**34,769**
Demand customers	63,590	64,149	62,570	62,829	62,933
Total load all customers	**96,025**	**96,629**	**95,757**	**96,838**	**97,702**

5.4 Basis of demand forecasts

Given the complexity around its demand forecasts, JGN engaged an independent demand forecaster to assist in establishing realistic demand forecasts.

To identify and appoint a suitably qualified expert forecaster, JGN conducted a competitive tender and investigated which forecasters were most frequently relied upon by independent Australian market operators such as VENCorp and NEMMCO. This led JGN to commission the NIEIR to develop demand forecasts for JGN's network for the next AA period.

5.4.1 Independent expert terms of reference

JGN's terms of reference[20] required NIEIR to quantify JGN's demand for the next AA period and to provide advice on the quantitative incremental impacts (both positive and negative) on:

- annual gas consumption of existing residential, business and large industrial consumers (i.e. customers)
- annual gas consumption of new residential, business and large industrial consumers
- hourly and daily demand for business and large industrial consumers using more than 10 TJ per year.

The contributing factors that JGN required to be considered were:

- market trends affecting the installation of existing gas appliances
- government energy efficiency policies
- implementation of the government's CPRS
- national hot water strategic framework
- national RET scheme
- any other factors which the expert considered relevant to the task.

JGN has provided a copy of NIEIR's expert report in Appendix 5.2.

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[20] NIEIR, *Natural Gas Projections NSW, Jemena Gas Networks to 2019: A report for Jemena Gas Networks (NSW)*, April 2009, Appendix 5.2

5.4.2 NIEIR economic forecasts

NIEIR's demand forecasts were predicated upon the most likely medium term outlooks for the Australian and NSW economies. However, NIEIR has recognised the uncertain economic environment facing Australia (and obviously NSW) over the next AA period. Sections 2 and 3 of the NIEIR report describe these uncertainties and the chosen economic parameters.

The NIEIR forecasts were prepared in early 2009 based on economic modelling and analysis as at December 2008.

5.5 NIEIR demand forecast approach

NIEIR assessed JGN's forecast demand during the next AA period by:

- producing an econometric demand forecast, taking account of the transitory near-term economic environment affecting gas consumption and connections
- making necessary adjustments to the econometric models to account for gas market factors, including the substitution of gas heaters by electric reverse cycle air conditioners, impact of AAA showerheads on hot water usage, replacement of failed hot water units and electricity to gas (**E to G**) hot water replacements
- making necessary adjustments to the econometric models to reflect government policy initiatives, including the Commonwealth insulation package, NSW Building Sustainability Index (**BASIX**) requirements, CPRS modelling, and mandatory energy performance standards
- producing an estimate of temperature sensitivity in terms of heating degree days (**HDD**), which was used by NIEIR to weather-normalise the volume forecast.

5.5.1 NIEIR gas forecast summary

Table 5-4 summarises NIEIR's forecast customer numbers and volume over the next AA period.

Table 5-4: Summary of NIEIR gas forecast over next AA period (Tables 5.1-5.4 of NIEIR report)

June years	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Customer numbers							
Residential	1,017,157	1,043,653	1,076,880	1,115,666	1,156,343	1,191,645	1,222,988
Small business	30,721	30,869	30,876	31,083	31,492	32,110	32,677
Total volume customers	**1,047,878**	**1,074,522**	**1,107,756**	**1,146,749**	**1,187,836**	**1,223,755**	**1,255,664**
Demand customers	421	423	424	424	424	425	426
Residential connections							
New estates and high rise	17,095	21,280	26,954	31,565	33,655	28,495	24,768
Electricity to gas	4,988	5,215	6,273	7,220	7,022	6,807	6,575
Total new residential	22,083	26,495	33,227	38,786	40,678	35,302	31,342
Total load (TJ)							
Residential	22,875	20,288	20,175	20,063	20,459	20,808	21,092
Business	12,227	12,072	11,961	11,966	12,128	12,451	12,777
Total volume customers	**35,102**	**32,360**	**32,135**	**32,030**	**32,587**	**33,260**	**33,869**
Demand customers	65,487	60,470	63,370	63,929	62,350	62,609	62,713
Total load	**100,589**	**92,830**	**95,505**	**95,959**	**94,937**	**95,868**	**96,582**
HDD index standard							
HDD index	489	486	483	480	477	474	471
Average residential load per year (GJ)							
Existing customers	20.8	19.9	19.2	18.4	18.1	17.9	17.7
New estates and high rise	18.9	18.6	18.3	17.9	17.5	17.2	16.9
Electricity to gas	14.6	14.3	14.2	14.0	13.9	13.8	13.8
Average load all residential	20.8	19.4	18.7	18.0	17.7	17.5	17.2
Maximum daily quantity large customers (MDQ)							
MDQ large customers	291.2	274.5	284.9	287.7	282.0	282.9	283.0

Notes:

1. The NIEIR report refers to 'contract' and 'tariff' market sectors. JGN now refers to the 'demand customer' and 'volume customer' sectors instead.
2. Gas load figures for 2008-09 are as shown in Table 4-4.

5.6 Overview of forecast results

The data in Table 5-4 is weather normalised to a standard of 489 HDD, including 2009.

5.6.1 Volume customer forecast

NIEIR forecasts that total volume customer growth will be 0.9 per cent per year over 2009 to 2019. NIEIR attributes this slow growth to price and market effects of the CPRS, Commonwealth and NSW energy policies and the increasing use of new more efficient gas appliances. The policies are outlined in section 5.8.5 of this AAI.

Average usage in new residential connections also reflects the impact of Commonwealth and NSW Government policy measures. Average usage by new connections (excluding E to G) is estimated at 18.9 GJ in 2009 falling to 16.9 GJ by 2015.

NIEIR forecasts small business volume growth over the 2009 to 2019 period at around 1.4 per cent per year.

5.6.2 Demand customer forecast

NIEIR forecasts demand customer gas usage for the JGN network to decline on average by 0.4 per cent per year. NIEIR's forecasts that demand customer load will fall in 2009-10 due to a general economic downturn, and in 2012-13 due to the introduction of emissions trading.

NIEIR suggests that there are significant downside risks to NSW manufacturing. There have been a number of major customer losses over recent years in NSW. Many manufacturers have either closed their NSW facilities altogether, or shifted their operations overseas to countries like China.

5.7 NIEIR methodological approach

This section outlines the key methodologies NIEIR employed in developing the forecasts for JGN's network.

5.7.1 Information supplied by JGN

JGN provided NIEIR with the following data:

- ten years of gas consumption data for the volume and demand customer sectors

- annual connections for various volume customer types including new residential, E to G and small business customers
- eight years of annual consumption and MDQ data for individual demand customers.

NIEIR then developed an eight to ten-year history of actual data for load and customer growth for the JGN distribution area.

5.7.2 Overall modelling approach

NIEIR developed forecasts of JGN natural gas usage within a regional economic model of the NSW economy. This model takes NIEIR's forecast of gross state product (**GSP**) by industry and disaggregates it into statistical sub-divisions across NSW.

5.7.3 Key economic inputs to NIEIR gas model

Table 5-5 shows the key economic inputs used by NIEIR in determining JGN's demand forecasts. These economic inputs were generated by NIEIR in its national and state economic models.

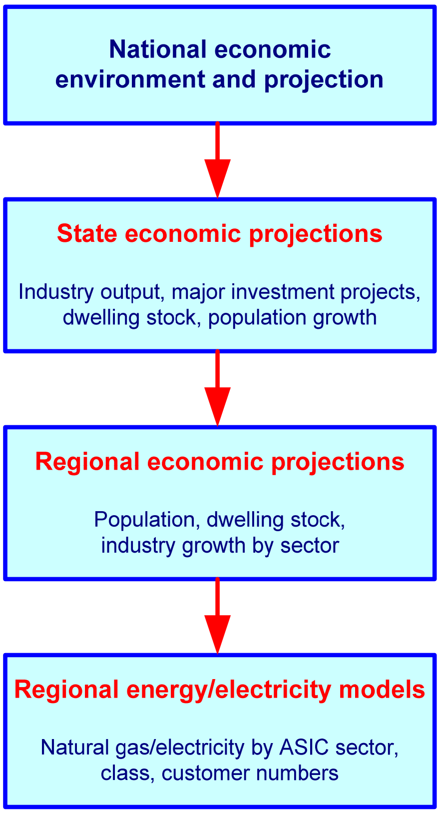
Table 5-5: NIEIR economic forecast NSW – macroeconomic aggregates and selected indicators (per cent change) (Table 3.2 NIEIR)

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	Compound growth rate 2008-09 to 2013-14
Private consumption	-1.1	0.2	0.9	2.9	3.5	3.0	2.1
Private business investment	-2.2	-19.5	1.4	28.4	0.8	5.3	1.9
Private dwelling investment	-7.2	10.0	9.6	14.4	10.8	-1.0	8.7
Government consumption	2.2	2.5	3.0	2.9	2.0	2.3	2.6
Government investment	12.1	0.1	18.5	29.8	2.9	7.4	10.8
State final demand	-0.5	-1.9	2.5	7.9	3.2	3.1	2.9
Gross state product	-0.9	-1.7	0.3	4.6	3.5	2.8	1.9
Population	0.9	0.8	0.7	0.8	0.9	0.9	0.8
Employment	0.0	-2.3	-1.4	0.9	2.5	2.2	0.4

NIEIR used the economic forecasts shown above in its regional economic model of NSW to determine how the overall NSW economic scenario mapped down to the JGN distribution area.

Key indicators at the regional level were population, dwelling stock and gross regional product by industry. Figure 5-1 demonstrates NIEIR's modelling approach.

Figure 5-1: NIEIR's regional energy model (NIEIR figure 4.2)



5.7.4 Key outputs from the NIEIR model

This section discusses the key gas demand outputs from the NIEIR model.

Residential customers and volumes

Residential gas usage is the main component of volume customer gas usage.

In summary, NIEIR developed the residential gas forecast by first determining an econometric forecast, where the key drivers were household incomes and energy prices, and then adjusting the forecast for its assessment of the impact of new energy policies.

Drawing on historic data from JGN, NIEIR disaggregated residential gas usage into new and established dwellings usage. NIEIR segregated new dwelling usage further into net new customers and E to G customers, that is, new customers on the existing gas network who will be mainly converting from electric appliances.

NIEIR prepared the residential forecasts on a weather normalised basis and incorporated the effects of real household disposable income and real gas prices.

NIEIR linked its residential customer forecasts to its projections of the dwelling stock.

The residential gas consumption forecast model also took account of federal and state energy and greenhouse policies including:

- the BASIX water and energy conservation program for new NSW homes as implemented in July 2006
- the program to review and standardise energy labelling of gas appliances, together with the development of mandatory energy performance standards (**MEPS**) for new gas appliances
- the increased penetration of energy efficient showerheads
- national hot water strategic framework—the effective banning of electric resistance hot water appliances from 2012
- the ongoing negative impact of high sales of reverse cycle air conditioning equipment
- the Commonwealth Government stimulus package with subsidies for home insulation
- other new policies or developments, such as the new NSW Energy Efficiency Target scheme (**NEET**) and the RET scheme.

These policies are discussed in detail in section 4.8 of the NIEIR report.

Small business usage

NIEIR forecast small business gas usage using a regression model which took account of commercial output growth and movements in real gas prices.

Demand customer load

NIEIR developed forecast loads for demand customers on an industry basis. JGN supplied NIEIR with eight years of gas usage and MDQ by individual customers. NIEIR then subdivided the data according to industry codes.

The industry regression models specifically related gas consumption to:

- the change in output for that industry within the gas distribution area
- the change in real gas prices for that industry incorporating lags in real prices to proxy the long run response or price elasticity.

NIEIR adjusted the output and price elasticities at the regional level to reflect differences in the gas intensity between industries and regions.

Forecasts of demand customer MDQ were also developed on an industry basis. NIEIR developed the MDQs from the forecast energy growth by industry together with an industry specific load factor.

5.8 Factors affecting load forecasts

5.8.1 Weather normalisation of JGN gas data

NIEIR obtained weather data from the Bureau of Meteorology (**BOM**) for the Sydney Observatory Hill weather station.

It is widely accepted that gas demand is a function of temperature expressed as HDDs where the number of HDD for a day is defined as the difference between the average temperature for the day and 18 degrees Celsius except that HDD for a day is zero if the average temperature is greater than 18 degrees Celsius.

In order to make meaningful comparisons of consumption from year to year and to establish a datum from which to forecast future consumption, it is necessary to normalise observed consumption for the differences in HDD between years. NIEIR estimates the standard number of HDD for a year to be 489, which is the average number of HDD for the six years from 2003 to 2008.

Table 4.2 in NIEIR's report shows billed volumes, temperature sensitivity coefficients, observed HDDs, standard HDDs, and normalised billed volumes for the volume and demand customer categories for the years 2004 to 2009. Table 5-6 summarises the impact of NIEIR's weather normalisation on JGN's historic demand.

Table 5-6: NIEIR weather normalisation (TJ) (Table 4.2 NIEIR)

Volume customers	Source	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09
Total billed load	Jemena, NIEIR	31,789	31,665	31,799	32,493	33,537	35,102
Weather normalised Billed	NIEIR	31,175	32,076	31,071	32,554	33,743	33,173
Abnormal weather load	NIEIR	614	-411	728	-62	-205	1,929
Demand customers	**Source**	**2003-04**	**2004-05**	**2005-06**	**2006-07**	**2007-08**	**2008-09**
Billed load	Jemena, NIEIR	64,230	64,050	62,988	64,857	65,452	65,487
Weather normalised billed	NIEIR		64,163	62,789	64,874	65,506	64,979
Abnormal weather load	NIEIR		-113	199	-17	-54	508

Note: It was established that Table 4.2 in the NIEIR report had transposed the residential and business weather normalised volume customer loads for years 2006 and 2008. The above table has corrected for this error.

Table 5-6 shows that the impact of NIEIR's weather normalisation is the significant reduction of 1,929 TJ in 2008-09 volume demand from the actual gas reported. NIEIR used the weather normalised 2008-09 volume customer gas load as the baseline for demand forecasts over the next AA period.

5.8.2 Existing and new residential customer usage

NIEIR's rationale for separately analysing existing customers and new customers was to assess how changes in government energy policies and building standards were affecting average consumption of natural gas by residential customers on JGN's network.

Table 5-7: Average residential customer usage in 2008-09 (GJ) (Table 4.3 NIEIR)

Average residential customer usage – existing and new customers	
Existing residential	20.8
Electricity to gas	14.6
New estates and high rise	18.9

Note: Values are weather normalised.

New residential customers consume on average around 2 GJ per year less than existing customers. This reflects a number of interacting factors, including:

- the efficiency of new versus existing water and space heating appliances
- the continued use of electric, solar-electric and heat pumps for residential hot water and the increased usage of reverse cycle air conditioners in New South Wales and the rest of Australia.

5.8.3 Gas usage in New South Wales

Every three years since 1994, the Australian Bureau of Statistics (**ABS**) has produced information relating to domestic energy use by conducting a monthly Labour Force Survey (**LFS**) supplemented by an Energy Use and Conservation Survey (**EUCS**). The latest is March 2008.

The EUCS covers a range of issues including energy sources, appliances and energy saving measures used in households. Despite possible sampling and other errors, it provides a useful overall picture of gas usage by households in NSW. NIEIR has analysed the EUCS data in section 4.6 of their report. The analysis is also summarised in Appendix 5.1.

5.8.4 Gas prices and the CPRS

In December 2008, when NIEIR was preparing its projections, a number of federal and state government policies had significant potential to affect gas prices. JGN notes that electricity prices would also be affected.

On 15 December 2008, the Commonwealth Government released its white paper on the CPRS. This paper confirmed an emission trading scheme is to be introduced by 2010-11. As noted, this now delayed by one year to 2011-12. The white paper outlines the final design of the CPRS, and a target range for reducing carbon pollution.

NIEIR's assessment of the white paper and the implications for carbon permit prices and gas prices are provided in section 4.7 of the NIEIR report attached.

5.8.5 Policies relating to gas (and electricity) consumption in NSW

There are a number of Commonwealth and NSW government policies and initiatives (besides the CPRS) that will have an effect on energy use and gas consumption. These policies cover construction of homes, alterations and extensions, and purchasing/replacement of household appliances and home insulation. All of these will affect future gas consumption in NSW.

NIEIR has considered these policies and their potential effects on gas usage, which are described in section 4.8 of its report. NIEIR's assessment is also summarised in the Appendix 5.1.

5.9 JGN final forecast and adjustments

JGN has made adjustments to NIEIR's forecasts over the next AA period for:

- an annual increase in volume customer load of 150 TJ resulting from JGN's gas marketing plan
- supply to a large new demand customer of 220 TJ per year, with a MDQ of 43 TJ.

In addition, JGN has quantified the number of new small business and large customer connections inherent in the NIEIR forecast, although there has been no adjustment to the forecast itself.

These adjustments are discussed below.

5.9.1 Residential demand adjustment

JGN has added another 150 TJ per year to NIEIR's forecast as a result of the gas marketing plan that JGN proposes will continue for the next AA period. Section 6.5.3 contains further details of this proposed expenditure.

In 2008 JGN implemented a significant change in the funding and direction of natural gas marketing, with the commencement of *Natural Gas The Natural Choice* marketing program. The program replaced the previous marketing approach based on funding gas retailers to drive the promotion of natural gas to end-consumers. The new approach focused on directly funding the development and implementation of a mass-market advertising and marketing campaign targeting end-consumers.

Initial key indicators confirm the positive results of the marketing campaign. However, given the time lag between marketing activity and the resulting effect on gas consumption, the results of the campaign were not evident in the historical consumption figures provided to NIEIR, and used by it to build its forecast models. As a result, NIEIR has not included any increase in gas consumption arising from the *Natural Gas The Natural Choice* campaign.

JGN has adjusted the NIEIR demand forecast by increasing the residential load figures by 150 TJ per year cumulatively commencing in 2009-10. Thus the NIER forecast was adjusted by 150 TJ in 2009-10, 300 TJ in 2010-11 and so on. The cumulative increase by 2014-15 is 900 TJ. Because of the small impact that the annual volume adjustment would have on average existing customer load, this average has been left unchanged.

Commercial in confidence

5.9.3 *Small business and demand customer new connections adjustment*

The NIEIR model for small business and demand customer gas volumes are is based on total market movements, and hence the numbers provided as part of its forecasts are net figures; i.e. new connections less disconnections. In order to develop a robust capex forecast JGN has estimated the number of new small business and demand customer connections based on historical numbers, and improved connection processes in the small business market. These numbers are shown in Table 5-10.

Table 5-10: Number of new connections small business and demand customers – year ending 30 June

	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Small business	881	975	1,075	1,175	1,251	1,335	1,410
Demand customer	3	3	3	3	3	3	3

5.9.4 JGN total forecast

The resulting JGN total forecast is shown in Table 5-11.

Table 5-11: JGN total gas forecast 2008-09 to 2014-15

June years	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Total load (TJ)							
Residential	22,875	20,438	20,475	20,513	21,059	21,558	21,992
Business	12,227	12,072	11,961	11,966	12,128	12,451	12,777
Total volume customers	**35,102**	**32,510**	**32,435**	**32,480**	**33,187**	**34,010**	**34,769**
Demand customers	65,597	60,690	63,590	64,149	62,570	62,829	62,933
Total load	**100,699**	**93,200**	**96,025**	**96,629**	**95,757**	**96,838**	**97,702**
Customer numbers							
Residential	1,017,157	1,043,653	1,076,880	1,115,666	1,156,343	1,191,645	1,222,988
Small business	30,721	30,869	30,876	31,083	31,492	32,110	32,677
Total volume customers	**1,047,878**	**1,074,522**	**1,107,756**	**1,146,749**	**1,187,836**	**1,223,755**	**1,255,664**
Demand customers	421	423	424	424	424	425	426
New network connections							
New estates and high rise	17,095	21,280	26,954	31,565	33,655	28,495	24,768
Electricity to gas	4,988	5,215	6,273	7,220	7,022	6,807	6,575
Total new residential	**22,083**	**26,495**	**33,227**	**38,786**	**40,678**	**35,302**	**31,342**
Small business	881	975	1,075	1,175	1,251	1,335	1,410
Demand customers	3	3	3	3	3	3	3
HDD index standard							
HDD index	486	483	480	477	474	471	468

June years	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Average residential load per year (GJ)							
Existing customers	20.8	19.9	19.2	18.4	18.1	17.9	17.7
New estates and high rise	18.9	18.6	18.3	17.9	17.5	17.2	16.9
Electricity to gas	14.6	14.3	14.2	14.0	13.9	13.8	13.8
Average load all residential	20.8	19.4	18.7	18.0	17.7	17.5	17.2
Maximum daily quantity demand customers (MDQ)							
MDQ demand customers	334.2	317.5	327.9	330.7	325.0	325.9	326.0

5.10 Use of demand forecasts in JGN's AAI

5.10.1 Customer categories and tariff classes

Throughout this chapter, the NIEIR demand forecasts have been presented in terms of 'demand' and 'volume' customers. However, to develop prices for reference services, JGN needs to translate the NIEIR forecasts, revised as in section 5.9 above, into tariff classes. This process is described in section 15.4.3 and detailed in confidential Appendix 15.2.

This is necessary in order to provide demand forecasts for each tariff class and each charging parameter within those tariff classes so that JGN can align its proposed prices to the forecasts demand and thereby ensure it recovers its cost of service. Section 13.8 describes this revenue and cost alignment.

5.10.2 Development of capex and opex forecasts

The RIN clause 2.2.2(f) requires 'an explanation of how the volume only forecasts have been used to develop the service provider's capex and opex forecasts'. This is provided below.

Capital expenditure

The capex forecast for market expansion is directly calculated from the number of new connections documented in this demand forecast. The volume of mains, services and meters are directly proportional to the forecast of new connections by customer class, and the capex is calculated by applying unit rates of construction to the individual volumes of mains, services and meters by customer class.

JGN's forecast system reinforcement capex is also affected by forecast demand. The system reinforcement capex forecast is based on disaggregated estimates of load growth at a localised level for individual local government areas. The performance of the networks at this localised level is reviewed regularly, in order to assess areas of network constraint and forecast the timing of required reinforcements.

Operating expenditure

The volume driven elements of JGN's O&M expenditure forecasts have been informed by the above market expansion capex as well as the NIEIR customer numbers set out in Table 5-10. This has included assessment of customer driven work orders and the incremental operating costs arising from the market expansion capex program. JGN has also relied upon the NIEIR demand forecast to establish its UAG forecast as set out in section 6.5.4.

5.11 RIN and rule 72 requirements

Table 5-12 below sets out RIN and rule 72 requirements met in chapter 5.

Table 5-12: Summary of RIN responses

RIN/rule 72 reference	RIN requirement	Where addressed in AAI
Demand		
RIN 2.2.2 Rule 72(1)(a)(iii)	(a) Provide in pro forma 11 minimum, maximum and average demand for the earlier access arrangement period and forecast maximum and average demand for the access arrangement period	Table **4-2** and pricing model Supporting information in section 4.2 for actual and section 5.9.4 for forecast Note: JGN does not have available forecasts of maximum and minimum total system wide demand.
	(b) Provide in pro forma 12 actual and estimated volumes for the earlier access arrangement period and forecast volumes for the access arrangement period by tariff class and pipeline service	Table 4-4**,** Table 5-3 and pricing model Supporting information in section 4.2 for actual and section 5.9.4 for forecast
	(c) Provide in pro forma 10 actual and estimated customer numbers for the earlier access arrangement period and forecast customer numbers for the access arrangement period by tariff class and pipeline service	Table 4-1**,** Table 5-1 and pricing model Supporting information in section 4.2 for actual and section 5.9.4 for forecast
RIN 2.2.2	Provide in the access arrangement proposal submission: (d) Details of the key drivers behind the demand forecasts	Section 5.9
	(e) The methodology that has been used to support the demand forecasts, including the key assumptions and inputs that have been used and how demand for pipeline services is differentiated	Sections 5.7 and 5.10
	(f) An explanation of how the volume only forecasts have been used to develop the service	Section 5.10.2

RIN/rule 72 reference	RIN requirement	Where addressed in AAI
	provider's capex and opex forecasts	
	(g) An explanation of any trends of demand and volumes over the earlier access arrangement period and access arrangement period	Section 4.2 for actual trends Sections 5.6, and 5.8 for forecast trends Appendix 5.3
Pipeline capacity and utilisation		
RIN 2.2.3 Rule 72(1)(d)	Provide in the access arrangement proposal submission to the extent that it is practicable to forecast pipeline capacity and utilisation of pipeline capacity over the access arrangement period, a forecast of pipeline capacity and utilisation of pipeline capacity over that period and that basis on which the forecast has been derived.	Section 5.3

6 Forecast operating expenditure

The NGR require JGN to submit with its AA its best forecast of opex that JGN would incur as a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

This chapter demonstrates how JGN has forecast its opex costs, and how these forecast opex costs comply with the relevant provisions of the NGR. It is structured as follows:

- *Section 6.1 Summary* – provides an overview of JGN's required opex forecasts over the next AA period.
- *Section 6.2 Law and rules requirement* – demonstrates that JGN's forecast opex is prudent, accords with good industry practice and provides for the lowest sustainable cost of pipeline services.
- *Section 6.3 Base year roll-forward approach* – explains that JGN has largely relied upon a roll forward of existing 'base' costs for 2008-09 to develop its recurrent opex forecasts and has augmented these with specific bottom-up forecasts for certain activities.
- *Section 6.4 Application of the base year roll-forward approach JGN opex* – details how JGN has applied its roll forward approach to recurrent opex costs.
- *Section 6.5 JGN forecast non-O&M costs* – provides JGN's forecast of its costs associated with administration and overhead, government levies, marketing, UAG, self insurance and debt/equity raising costs.
- *Section 6.6 JGN forecast O&M costs* – provides JGN's forecast outsourced O&M costs.
- *Section 6.7 Rule compliance* – demonstrates that JGN's compliance with the NGR.
- *Section 6.8 Key performance indicators for the next AA period* – set out JGN's KPIs for the next AA period.
- *Section 6.9 RIN and rule 72 requirements* – maps the RIN and NGR rule 72 requirements to the relevant sections, chapters and regulatory models.

6.1 Summary

Opex is a major component of network expenditure accounting for approximately 36 per cent of JGN's total cost of service. Over the current AA period JGN has achieved cost efficiencies relative to the IPART approved opex forecast.

JGN has forecast its opex with regard to the costs it will incur through its management structure and through its outsourcing of asset management activities. This structure and outsourcing are described in chapter 3.

JGN's forecast opex over the next AA period is shown in Table 6-1.

Table 6-1: JGN forecast opex

			Next AA period				
	2008-09 (adjusted base year)	**2009-10**	**2010-11**	**2011-12**	**2012-13**	**2013-14**	**2014-15**
Non-O&M	48.31	47.49	49.54	54.22	61.96	64.10	66.18
O&M	81.85	79.38	84.60	84.21	87.19	89.88	93.26
Total forecast opex	**130.16**	**126.86**	**134.13**	**138.43**	**149.16**	**153.98**	**159.43**

JGN has employed two methodologies for forecasting its opex costs in the next AA period:

- *base year roll-forward approach* – which JGN has applied to the majority of its recurrent opex over the next AA period:
  - JGN's administration and overheads (**A&O**), which is one component of its non-O&M costs
  - most of the fee that JGN will pay to JAM for asset management services under the new AMA, which is the principal component of its O&M costs.
- *specific year-by-year forecasts* – for a small number of particular costs that JGN will incur where base year costs are not representative of the future:
  - government levies
  - marketing
  - unaccounted for gas

– self insurance

– site remediation.

JGN's opex forecasts are arrived on a reasonable basis and the costs of a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

To further support this view, JGN commissioned Economic Insights to assess JGN's input productivity for its historic and forecast opex costs. Economic Insights report is provided in Appendix 6.7. It concludes that JGN's historic and forecast opex costs compare favourably with their network peers in Victoria.

6.2 Law and rules requirements

When approving JGN's revised AA, the AER must have regard to the NGO, and also section 24(2) of the NGL which affords a service provider with an opportunity to recover at least its efficient costs.

NGR rule 74 requires that:

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

In addition to the general NGR forecast provisions set out in section 1.4 and above, rule 91 sets out specific criteria governing opex:

> Opex must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.

JGN considers that its forecasts comply with these rules.

Rule 91(2) provides that the AER's discretion under this rule is limited.[21]

[21] Rule 40(2) of the NGR sets out the requirements for an AER limited discretion decision.

6.3 Base year roll-forward approach

JGN has separately forecast its opex costs for each material category of costs and in accordance with the cost categories determined by IPART. JGN's materiality thresholds required by RIN section 2.3.5.2(b)(ii) are therefore aligned with the cost categories set out in Table 6-6 for non-O&M costs and Table 6-12 for O&M costs. JGN has employed two methodologies for forecasting its opex costs in the next AA period:

- the base year roll-forward approach
- specific forecasts.

JGN has determined specific year-by-year forecasts for a number of particular costs that JGN will incur where base year costs are not representative of the future:

- government levies
- marketing
- unaccounted for gas
- self insurance
- site remediation.

This section describes the base year roll-forward approach, which JGN has applied to the majority of its recurrent opex over the next AA period, in particular:

- JGN's A&O, which is one component of its non-O&M costs
- most of the fee that JGN will pay to JAM for asset management services under the new AMA, which is the principal component of its O&M costs.

The base year roll-forward approach involves three steps:

Step 1 – Gathering information on the firm's current and historic cost

JGN gathered information on the firm's current and historic opex in order to determine the quantum and breakdown of its opex costs of supplying reference services in its base year. The base year would be the most recent year for which full-year actual costs are available (or will become available) prior to the AER's determination being made.

Step 2 – Adjusting the base year

JGN then adjusted its base year costs to create a platform for forecasting costs in the next AA period by:

- re-aligning costs to fit with Jemena's current corporate structure and JGN's new outsourcing arrangements
- subtracting costs associated with one-off events during to base year and circumstances that are not expected to endure
- adding costs associated with foreseeable incremental step changes in expenditure.

Step changes involve increases or decreases in costs due to new regulatory obligations, or changes in the operating environment that are outside the JGN's control, such as climate change policies.

Step 3 – Rolling the base year forward

Finally, JGN rolled the base year costs forward, adjusting (escalating or deflating) for:

- forecast impact of network growth (customer numbers, energy usage, system demand and capacity constraints) on the 'amount of work' that will need to take place
- forecast real change in the input costs for doing the work (real escalation in the costs of labour and materials, as well as general inflation)
- forecast inflation.

6.4 Application of the base year roll-forward approach

6.4.1 Collecting historical base year costs

The year from 1 July 2008 to 30 June 2009 (**2008-09**) is JGN's base year. At the time of this submission, JGN's actual cost data for the full 2008-09 year is not yet available. JGN has relied upon forecasts to the last 3 months of direct costs and the last 4 months of indirect costs.

Jemena conducted a Whole of Business Cost Allocation (**WOBCA**) project to collect and quantify direct and indirect costs associated with JGN's service provision using the best available information from its historical records.

The nature of JGN's historical costs in 2008-09 reflects the nature of JGN's outsourcing at the time and a previous corporate structure. To enable JGN to fully apply its roll-forward approach, the WOBCA process broke down and quantified JGN's direct costs and overheads, and JAM's underlying direct costs and overheads. This has enabled each type of cost to be adjusted and/or rolled forward separately.

Expert review of WOBCA

In its expert report in Appendix 6.1, PriceWaterhouseCoopers (**PwC**) describes this process and verifies the robustness of the cost allocation methodology and the results. PwC concluded that:

- The WOBCA methodology is simple, justifiable, transparent, consistent and auditable
- for all costs allocated to JGN, the WOBCA methodology has been accurately applied.

Representative base year

JGN considers that, subject to the adjustment set out in section 6.4.2, its base year costs are representative of a typical year and therefore suitable as a basis for forecasting purposes.

JGN did seek from JAM its underlying costs for the three previous years of the current AA period so that a time series comparison could be made. JAM was unable to provide these costs in a manner suitable for reliance by JGN. This was a consequence of structural changes in ownership which means that Jemena no longer has access to certain data from its predecessor entities.

JAM sought an expert review of the historic information it had attempted to construct. PwC advised in the letter provided in Appendix 6.2 that this was not possible based on the same rigorous terms it applied to its review of the 2008-09 cost data.

6.4.2 Adjusting the base year

Reclassification of some costs

Jemena's current corporate structure and the new AMA provides for JGN to take primary responsibility for its business management. Accordingly, costs associated with the JGN commercial team and regulatory team and an appropriate allocation of Jemena's corporate overhead have been applied to the JGN administration and overhead cost base cost.

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The WOBCA process identified among Jemena's ESF costs some costs that JAM incurs as a direct result of serving JGN: JAM's Sydney property rents and its telecommunications for remotely read meters. Accordingly, these costs are now classified as JAM direct costs.

New outsourcing

JGN's new AMA also provides for a different commercial margin to that inherent in the previous arrangements.

One-off events

JGN and JAM have identified a number of costs which are not representative of a typical year of recurrent opex costs. These relate to items which are one-off in nature or have been higher in 2008-09 than may be the case in a typical year.

For JAM O&M these one-off costs are shown in Table 6-2.

Table 6-2: JAM O&M one-off costs ($million, $2009)

Item	Description	One-off cost
Branding	Costs associated with the development and roll out of the Jemena brand	0.10
One-IT	The development and implementation of a shared SP AusNet & Jemena IT delivery service, implemented through the establishment of EBS	1.60
BRP Blueprint	Business process review project incorporating the standardisation of business processes such as costing and estimating, and time writing	0.50
Domain	A joint project with SP AusNet to develop synergies through the transfer of functions and activities between Jemena and SP AusNet, and having these services jointly provided to both businesses	0.10
Project Zinc	The development and implementation of the restructured organisation to align with the Jemena business strategy	0.40
Total one-off costs ($2009)		**2.70**
Total one-off costs ($2010)		**2.77**

For JGN in-house costs, these costs are shown in Table 6-3:

Table 6-3: JGN O&M one-off costs ($million, $2009)

Item	Description	One-off cost
Branding	Costs associated with the development and roll out of the Jemena brand	1.60
Total one-off costs ($2010)		**1.64**

Steps changes

JGN and JAM have identified items that will affect JGN's future cost base that are not in the base year. These items represent step changes in JGN's operating environment and regulatory obligations—for example, changes in standards, compliance requirements, and new asset types with new operational and maintenance requirements. They total $4.1 million per year.

Appendix 6.3 details the individual step change items, their causation and the basis of their forecast cost.

6.4.3 Rolling forward the base year

Growth in gas consumption and customer connections

Many of JGN's operating activities and costs will grow in line with the growing demand for its pipeline services:

- the level of JGN's market expansion and growth in customer connections drives increases in its outsourced O&M activity
- growth in gas consumption drives increases in UAG and JGN's demand for carbon permits.

To determine its reasonable forecasts of growth in gas consumption and customer connections, JGN has drawn upon an independent expert report from NIEIR.

JAM provided JGN with a forecast of its O&M costs based on volumes of work orders arising from the NIEIR forecast customer numbers and the market expansion capex plan. JAM provided these costs in 2008-09 dollars so that JGN could then apply its own view of input cost escalation.

JGN has assumed that JGN's and JAM's indirect costs will not grow as a consequence with increases in gas consumption or customer connections.

Input cost escalation

JGN commissioned Competition Economists Group (**CEG**) to estimate cost escalation factors in order to forecast changes in the input costs of JGN's proposed expenditure for the next AA period. JGN requested that CEG develop cost escalation factors for the following network inputs:

- labour paid under enterprise bargaining agreements (**EBAs**)
- labour paid under individual contracts
- aluminium
- steel
- plastics
- concrete.

CEG's estimates of JGN's input cost escalation factors are set out below.[22] The full report is included in Appendix 6.4.

Table 6-4: Opex escalation factors for JGN, (per cent, real)

Opex	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
EBA EGW labour	1.8	1.3	2.1	1.9	1.6	1.8
Contract EGW labour	1.8	1.4	2.1	4.0	4.4	4.1
Aluminium	-7.9	9.9	9.0	7.7	6.6	5.9
Steel	-18.0	8.4	6.3	1.5	0.9	0.8
Polyethylene	0.6	2.0	1.1	0.3	0.2	0.2
Concrete	3.0	1.5	3.4	3.0	1.8	0.9

CEG observe that in general, the methodology applied in its report to estimate escalation factors is characterised by a high degree of transparency over the use of input data to estimate escalation factors.[23] CEG also noted that the methodology is broadly consistent with the methodology applied by the AER in its calculation of escalation factors for its final determinations for the New South Wales and Tasmanian electricity businesses.

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[22] ,CEG, *Escalation factors affecting expenditure forecasts - A report for Jemena Gas Networks*, June 2009, p. 28.

[23] CEG, Op. cit. p. 2.

Carbon scheme

JGN also requested that CEG separately estimate the extent to which the planned introduction of an emissions trading scheme is likely to affect the escalation factors for aluminium, steel, plastics including nylon-11 and polyethylene, and concrete.

CEG separately estimated the effect that the Commonwealth Government's proposed ETS will have on the escalation factors for commodities. This analysis was based on the Australian Bureau of Statistics Input - Output tables, which allowed CEG to track the extent to which an increase in the price of carbon dioxide emissions will have on the price of final outputs over a range of industries. The effect of increasing emissions prices between 2009-10 and 2014-15 on the escalation factors estimated above is shown in Table 6-5.

Table 6-5: Effect of emissions trading scheme on escalation factors (per cent)

Input	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Aluminium	0.0	0.0	0.3	0.4	0.1	0.0
Steel	0.0	0.0	0.7	1.2	0.1	0.1
Plastics	0.0	0.0	0.5	0.8	0.1	0.1
Concrete	0.0	0.0	0.3	0.5	0.1	0.1

Given the lack of certainty over future emissions prices and the nature of industry relationships in the future, the estimates reported above are necessarily approximate. Nonetheless, CEG considers them to be reasonable and the best estimate possible in the circumstances.

6.5 JGN forecast non-O&M costs

Table 6-6 summarises JGN's forecast opex excluding O&M activities.

As indicated in section 6.3, JGN has forecast its A&O using the base year roll-forward approach. JGN has forecast its other non-O&M costs on a specific year by year basis: government levies, marketing, unaccounted for gas, self insurance and debt/equity raising costs. Sections 6.5.1 to 6.5.6 explain how this was done.

Table 6-6: JGN forecast operating costs excluding O&M over next AA period

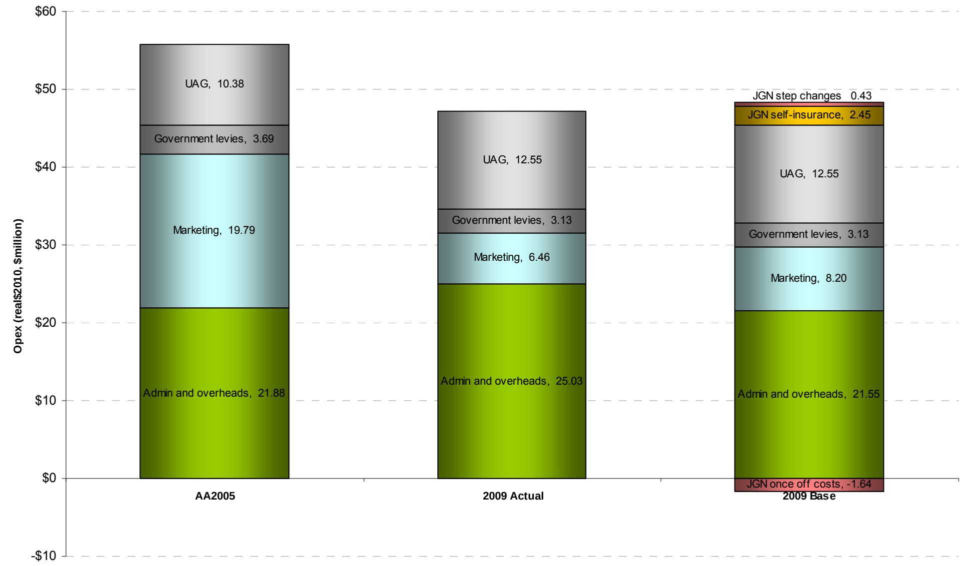
			Next AA period				
Category	**2008-09 (adjusted base year)**	**2009-10**	**2010-11**	**2011-12**	**2012-13**	**2013-14**	**2014-15**
Administration and overhead							
Base cost	23.19	21.66	22.12	22.70	23.61	24.57	25.50
One-off events	-1.64	0.00	0.00	0.00	0.00	0.00	0.00
Step changes	0.43	0.43	0.44	0.45	0.47	0.48	0.50
Government levies	3.13	3.13	3.13	3.13	3.13	3.13	3.13
Marketing	8.20	8.20	8.20	8.20	8.20	8.20	8.20
Unaccounted for gas	12.55	11.62	11.41	11.40	11.26	11.40	11.55
Carbon costs	0.00	0.00	0.00	4.04	10.96	11.91	12.85
Self insurance	2.45	2.45	2.45	2.45	2.45	2.45	2.45
Debt raising	0.00	0.00	1.79	1.85	1.90	1.95	2.00
Total JGN non-O&M opex	**48.31**	**47.49**	**49.54**	**54.22**	**61.96**	**64.10**	**66.18**

Note:

1. JGN proposes to capitalise equity raising costs to its RAB rather than include it in its forecast cost of service and cash flows.
2. This forecast is therefore subject to change if JGN's capex, cost of service or cash flow assumptions are varied.

Figure 6.1 shows JGN's administration and overhead in the base year (adjusted) and other non-O&M costs, which is $7.4 million less than the equivalent costs in the IPART approved allowance for 2008-09.

Figure 6.1: JGN in-house management and other non-O&M costs



Note. In this diagram, for the 2009 base year, administration and overheads of $21.55 million exclude one-off costs of $1.64 million. The value of administration and overheads including one-of costs is $23.19 million.

There are key areas of difference in marketing costs which is $11.6 million. Section 6.5.3 discusses the manner in which JGN will incur marketing costs over the next AA period.

6.5.1 Administration and overheads

JGN's A&O relate to the management of the JGN business. They comprise:

- the cost of JGN's management activities that are undertaken by the Infrastructure Investments division
- an allocation of Jemena corporate overheads to JGN's share of costs of Jemena's enterprise support functions
- other JGN specific overheads, which include:
  - costs relating to JGN's properties
  - costs relating to the JGN's owned and leased land on which trunk receiving station sites are located
  - environmental monitoring of properties.

These management activities and enterprise support functions are described in section 3.2. JGN has used the primary allocations set out in the PwC review of WOBCA in Appendix 6.1 to determine its share of Jemena corporate overheads and its specific overheads.

JGN has escalated these costs using the CEG determined escalators. In applying this escalation, JGN has employed input weights specific to these JGN costs, which are different to those used for JAM. This means the escalation factors differ from those JGN applied to JAM overheads.

6.5.2 Government levies

Government levies comprise the NSW mains tax and licence (i.e. authorisation fee) payable to IPART to recover regulatory costs.

Mains tax is governed by section 611 of the Local Government Act and is paid to the local government councils each year. It is subject to two independent audits, one being for the Sydney metropolitan local councils and the other for the NSW country councils which have gas distribution pipes within their jurisdiction. JGN has forecast its mains tax costs based on historic trend.

JGN pays annual licence fees to IPART. JGN has forecast these based on an extrapolation from recent fees. This means that JGN has reduced the current licence fee forecast to $800,000 based on the 2007-08 payment. JGN understands that the AER will be funded differently from the previous regulator IPART which is why the fee has reduced from historical levels.

6.5.3 Marketing

JGN conducts marketing in the form of network marketing and incentive payments to help promote greater use of gas and offers incentives to install natural gas appliances with the aim of increasing the volume of residential gas transported through its network. Rather than outsource these activities, JGN retains a direct management of marketing and market development functions to ensure optimal development of its network.

Current Consumer Trends

JGN's average residential consumption has been reducing over the past eight years, and analysis indicates that gas consumption in existing homes is declining by approximately 440 TJ per year. JGN estimates that 240 TJ of this annual decline is a result of the failure of existing gas consumers to replace their natural gas heaters when they have reached the end of their useful lives (estimated to be 15 years). It appears consumers are switching to previously installed reverse cycle air conditioners to provide heating, or other low capital cost electric heaters, rather than replacing the more expensive to purchase gas heater. It is also evident that gas is failing to attract a significant market share of the 50 per cent of existing gas consumers that currently do not have gas heating**.**

Marketing strategy and objectives

JGN's current AA opex includes a marketing allowance of $98.1 million over 5 years, or around $19.6 million per year. To date, JGN has spent a total of $18.2 million for the four years to June 2009, with $6.5 million spent in the year ending June 2009.

Until 2007, JGN based its marketing strategy primarily on NSW retailer incentives to fund promotion of natural gas. An assessment of this strategy in 2007 determined that this approach had declined in effectiveness in recent years, and JGN developed and implemented a new strategy in 2008.

JGN's new marketing strategy involves generic promotion of natural gas and directly managing and controlling the marketing spend and the targeting of incentive payments to key appliance influencers such as gas appliance installers, rather than gas retailers.

The primary objective of the marketing program is to significantly increase the sale and installation of gas heating appliances in NSW by establishing natural gas as a highly desirable and environmentally friendly energy option. JGN is targeting a 50 per cent growth in gas heating appliance sales, which would translate to increased gas consumption of approximately 150 TJ per year, for each year of the program.

JGN aims to achieve this objective by two means:

- *a mass market advertising campaign* – A campaign focused on TV, print and trade exhibitions and an interactive website (www.thenaturalchoice.com.au) to allow consumers to identify the appropriate appliances for their needs and find where to view and purchase them. The campaign will target both consumers, and tradespeople who influence consumer purchases, such as plumbers and builders.

- *targeted incentives* – An incentive scheme focused on appliance installers to encourage installation of gas appliances, where the upfront cost is a key driver of the purchasing decision. Electric to gas hot water conversions is a key market where incentives are critical to maintaining a significant market share. This is especially important given the range of Government grants and schemes that generally advantage electric technologies over gas, specifically the RET rebates for electric heat pump systems.

JGN has assessed the prudency of this marketing by comparing the value of the annual marketing spend and the present value of the cumulative revenue over the life of the incremental appliances installed as a result of the marketing program.

Based on an $8.2 million marketing spend achieving an incremental increase in residential volumes of 150 TJ per year, the present value of the future cash flows is approximately $10 million.

Table 6-7: The current marketing program costs for 2008-09

	2008-09
Appliance incentives	0.82
Natural gas marketing campaign	5.64
Total market program costs	6.46

The forecast marketing operating costs are set out in Table 6-8.

Table 6-8: Forecast marketing opex costs

	2010-11	2011-12	2012-13	2013-14	2014-15
Marketing opex	8.20	8.20	8.20	8.20	8.20

Note: The 2009-10 and 2010-11 forecasts reflect the appliance incentive costs attributable to the current scheme, including upward adjustments for widening of the scheme to include all gas appliance installers, instead of only retailers. This widening will result in increased claims for rebates/incentives.

Interaction with demand forecast

The NIEIR demand forecast did not initially include any impact of gas marketing. JGN considers that the baseline residential gas demand forecast should be increased by 150 TJ per year cumulatively over the five year regulatory period to reflect the inclusion of the marketing program in the opex submission. JGN has adjusted the NIEIR forecast accordingly as described in section 5.9.

6.5.4 Unaccounted for gas

The difference between the total volume of gas received into the network and the total quantity delivered to customers (i.e. gas measured as received by the network less the amount measured by all active gas meters) is referred to as UAG. JGN must buy replacement gas which it sources through competitive commercial arrangements.

In addition, the proposed CPRS will require JGN to procure carbon permits for the proportion of UAG that is estimated to be leakage, that is, physical gas losses. The NGER laws set the technical requirements for estimating carbon emissions. The NGER laws provide a methodology for estimating leakage (fugitive emissions) for gas networks. The methodology deems JGN's fugitive emissions to be equal to 1.32 per cent of the total gas received into the network.

The forecast UAG related opex costs for each year of the next AA period are set out in Table 6-9. The basis of these forecasts is set out in the following sections.

Table 6-9: Forecast UAG costs

Year	2010-11	2011-12	2012-13	2013-14	2014-15
UAG	11.41	11.40	11.26	11.40	11.55
Carbon Permits	0.00	4.04	10.96	11.91	12.85

UAG costs

JGN competitively procures gas for UAG. To date this has involved competitive tender, but JGN may replace or supplement this with purchases made through the STTM during the next AA period. The STTM may provide additional competitive options for JGN to commercially procure gas, whether directly from the market or from trading participants in that market.

Under JGN's 2005 AA, allowable costs are based on fixed target UAG rates for each year but variation in the actual average $/GJ price paid by JGN to purchase gas during a year is a pass-through in the annual tariff variation mechanism for network tariffs. JGN proposes to retain this arrangement with modification to accommodate the UAG-related costs associated with carbon permits and to better align the UAG recovery with JGN's controllable rate of UAG.

JGN currently receives compensation for UAG up to a target rate of 2.1 per cent. JGN can benefit by keeping this compensation where it achieves UAG of less than 2.1 per cent but bears additional unfunded costs where UAG is over 2.1 per cent. Over the past three years, JGN's UAG as reported to IPART has averaged 2.4 per cent, resulting in financial losses.

As well as physical loss, UAG also represents the combined energy measurement uncertainties for a complex physical system. Analysis of the contributing factors to UAG set out in Appendix 6.8 shows that at levels of UAG below 3 per cent, overall UAG performance can be equally representative of factors outside JGN's control and that the level of contribution from factors in JGN's control are at efficient levels. This analysis demonstrates that a level of UAG of up to 2.7 per cent should be considered efficient for the JGN network.

For this review, JGN has forecast UAG costs as follows:

- gas demand volumes are as per the NIEIR forecast of June 2009
- the UAG volumes are calculated as 2.1 per cent of total gas received by the network

- from 2010, the wholesale NSW gas prices were taken from the ACIL Tasman report prepared for NEMMCO.[24]

In addition to the forecast UAG costs at a target rate of 2.1 per cent, JGN proposes to retain annual tariff variation provisions for UAG procurement costs and for UAG volumes. JGN proposes that the annual tariff variation include compensation for UAG costs and volumes up to an efficient tolerance level of 2.7 per cent. Section 16.5.1 describes this tariff variation mechanism while Appendix 6.8 provides further justification for the 2.7 per cent UAG tolerance rate.

Carbon permit costs

The NGER laws set the technical requirements for measuring carbon emissions that are assumed to apply to emitters under the CPRS. Emitters must calculate emissions by source, including gas transmission and distribution, vehicles, electricity source and contractors.

NGER laws let emitters choose for each source from several calculation methods.[25] Using these methods, JGN emits about 447,184 tonnes of equivalent carbon dioxide (**t CO2e**)[26] per year.

JGN is likely to only be liable under the CPRS for emissions that it releases or is deemed to release directly, such as:

- fugitive emissions
- gas combustion.

JGN's fugitive emissions are estimated to be 440,686 t CO2e in 2008-09.

JGN, or an entity on behalf of JGN, will buy carbon permits to offset the carbon cost of fugitive emissions from its distribution network. In effect, this is a tax on carbon which needs to be recovered by JGN.

JGN proposes that these costs will be recovered through the regulatory process, and linked to UAG as an uncontrollable cost pass through allowance. Section 16.5.1 provides further details.

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[24] ACIL Tasman, *Fuel Resource, New Entry and Generation Costs in the NEM*, April 2009, p. 23.

[25] Methods set out in: Department of Climate Change, *National Greenhouse and Energy Reporting System Measurement, Technical Guidelines*, Version 1.1, 2008.

[26] For natural gas, *equivalent* carbon dioxide (CO2e) includes both *actual* carbon dioxide (CO2) and methane (CH4) emissions.

JGN has forecast an allowance for fugitive emissions for each year of the next AA period, calculated as the product of forecast fugitive emissions rate of 2.4 per cent and an assumed carbon price.

JGN obtained the carbon price forecast from the ACIL Tasman report prepared for NEMMCO.[27] The forecast carbon prices are shown below.

Table 6-10: Emission permit price[28]

Year	Price ($/tonne CO2-e)	Price adjusted by JGN[29]
2009-10	0.00	0.00
2010-11	23.39	0.00
2011-12	24.19	9.54
2012-13	26.14	26.14
2013-14	28.09	28.09
2014-15	30.04	30.04

6.5.5 Self insurance

JGN insures for a number of key risks. In addition to these insured risks, JGN faces residual self insurance costs for:

- risks for which insurances are available commercially, but which JGN does not take out coverage
- risks for which JGN has coverage but faces residual risks associated with deductibles (excesses) and caps on coverage
- risks for which JGN cannot commercially procure insurance.

JGN has engaged Marsh Risk Consulting (**MRC**) to prepare an expert quantification of these self insurance costs. MRC's expert report is provided in Appendix 6.5. This report identifies JGN's annual self insurance risks to be $2.36 million per year in nominal dollars as at 1 January 2009 or $2.45 million in $2010 dollars.

27 This is consistent with the carbon permit assumptions relied upon by CEG (see appendix 7.5).

28 ACIL Tasman: *Fuel Resource, New Entry and Generation Costs in the NEM*, April 2009, p. 23.

29 Allowing for one year delay in CPRS, and substituting $10.00 in year 2011-12 in nominal dollars.

Table 6-11: JGN self insurance events (real, $nominal as at 1 January 2009)

Type of self insurance	Event	Annual cost
Uninsured	Environmental contamination & counterparty credit risk	1.26
Deductable or cap	Key asset damage, key asset failure, general public liability claims at or below the deductible limit & counterparty credit risk	0.28
Uninsurable not pass-through	Counterparty credit risk	0.82
Total ($nominal)		2.36
Total ($2010)		2.45

6.5.6 Debt and equity raising costs

Jemena incurs costs when it raises funds, both debt and equity, to spend on JGN's capital program.

Debt raising costs are incurred each time debt is rolled over, and may include underwriting fees, legal fees, company credit rating fees and other transaction costs.

Equity raising costs are incurred each time equity is raised and may include legal fees, brokerage fees, marketing costs and other transaction costs. These are upfront expenses, with little or no ongoing costs over the life of the equity.

For consistency with the NGR, JGN proposes debt and equity raising costs that would apply to a benchmark efficient firm that:

- has JGN's proposed RAB including its capital program
- maintains a constant leverage ratio of 60 per cent throughout the next regulatory period.

JGN proposes benchmark efficient:

- debt raising costs of 0.125 per cent per year on its outstanding debt balance at the start of the year, including capital expenditure (net of disposals and capital contributions) that is assumed to occur at the start of the year
- equity raising costs of 1 per cent on equity raised internally (through dividend reinvestment) and 2.75 per cent on equity raised externally—assuming a dividend payout ratio of 70 per cent and a dividend reinvestment take-up rate of 30 per cent.

JGN proposes expensing debt raising costs as an administration and overhead cost and capitalising equity raising costs to its RAB.

Given JGN's forecast cost of service for the next regulatory period and the above assumptions, the forecast value of equity raising costs is immaterial. Hence, JGN proposes no such costs for the next regulatory period, but proposes to revisit this position if either the forecast cost of service or the equity raising cost assumptions change.

6.6 JGN's operating and maintenance costs

The Table 6-12 summarises JGN's forecast opex excluding O&M activities.

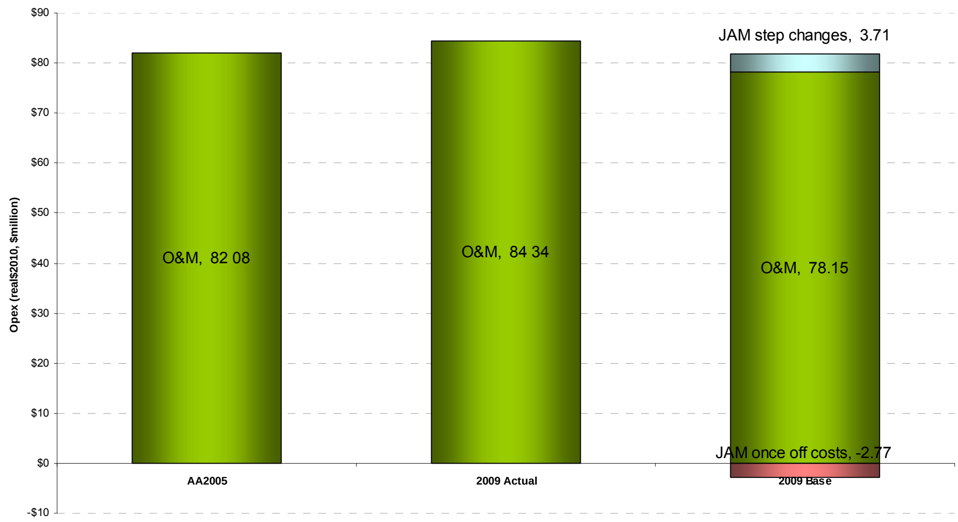
As indicated in section 6.3, JGN has forecast most of the fee it will pay to JAM using the base year roll-forward approach and JGN has forecast the other component of the fee it will pay JAM on a specific year by year basis: site remediation. Section 6.6.1 explains how this has been forecast.

Table 6-12: JGN forecast O&M costs over next AA period

			Next AA period				
Category	**2008-09 (adjusted base year)**	**2009-10**	**2010-11**	**2011-12**	**2012-13**	**2013-14**	**2014-15**
JAM asset management services							
One-off events	-2.77	0.00	0.00	0.00	0.00	0.00	0.00
Step changes	3.71	3.76	3.82	3.91	4.01	4.12	4.22
Total JGN O&M opex	**81.85**	**79.38**	**84.60**	**84.21**	**87.19**	**89.88**	**93.26**

Figure 6.2 shows adjusted base year O&M costs and compares these against the equivalent indirect cost categories in IPART's 2005 final decision. This comparison shows that base year opex is marginally below the IPART allowance for this cost category and is below the costs JGN incurred under its previous outsourcing arrangements. This in part reflects step changes in JGN's O&M activities.

Figure 6.2: Representative base year O&M costs



Notes.

1. In this diagram, for the 2009 base year, O&M of $78.15 million excludes one-off costs of $2.77 million. The value of O&M including one-off costs is $80.92 million.
2. JAM step changes and one-off costs exclude the margin. Under the AMA, JAM will charge JGN a margin on top of these costs.

Commercial in confidence

Commercial in confidence

Commercial in confidence

6.7 Rule compliance

JGN's opex forecasts are made on a reasonable basis and represent those of a prudent service provider acting efficiently in accordance with accepted good industry practice to achieve lowest sustainable costs of providing the reference services.

Infer current costs are efficient

In the current regulatory period, Jemena has had an incentive to minimise its costs overall to maximise its commercial position. This incentive has been created by the fixed opex allowance that IPART provided to JGN in 2005, and the fixed fee that JGN has paid JAM up to 31 July 2009.

Given this incentive, the AER can infer that the base year build up of costs for JGN and the underlying costs of JAM are efficient.

Commercial in confidence

Commercial outsourcing

JGN has in-house functions to manage its costs and its outsourcing of asset management activities. Through this model, and in accordance with a formal commercial process, JGN has negotiated an asset management agreement with JAM that reflects JGN's interests in containing its costs and in ensuring that JAM provides a level of service that reflects good industry practice. This agreement reflects one that which would be negotiated at full arms length.

Forecast methods

JGN's application of the base year roll-forward and approach, and its year-by-year forecasts of other specific costs is reasonable and based on the best information available, including:

- Jemena's internal cost information and allocation methodology, which PwC has verified
- reliable expert reports that provide reasonable demand forecasts and estimates of cost escalators
- JAM's asset management plan, which sets out how its O&M activity will increase with demand
- this submission demonstrates that JGN's opex forecast are made on a reasonable basis.

Future efficiency

Further, JGN's forecasts demonstrate productivity rates that benchmark favourably with other gas networks.

As discussed in section 1.3, over successive AA periods JGN has been subject to ambitious efficiency targets. These were as high as 3 per cent[30] in IPART's 2000 decision before declining to 1.5 per cent[31] in its 2005 decision. The decline

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[30] IPART Final Decision, *Access Arrangement for AGL Gas Networks Limited Natural Gas System in NSW*, July 2000, p. 133.

[31] IPART Final Decision, *Revised Access Arrangement for AGL Gas Networks*, April 2005, p. 111.

reflected recognition by IPART of the diminishing marginal efficiencies available to JGN as it approaches its efficiency frontier.

JGN commissioned Economic Insights to review its opex productivity. The outcome of this review is provided in Appendix 6.7.

Figure 6-3 is taken from this report. It shows that JGN has achieved rates of opex productivity growth that exceed those of its peers in Victoria.

Figure 6-3: JGN and Victorian gas distributors' partial factor productivity indices, 1998-2009

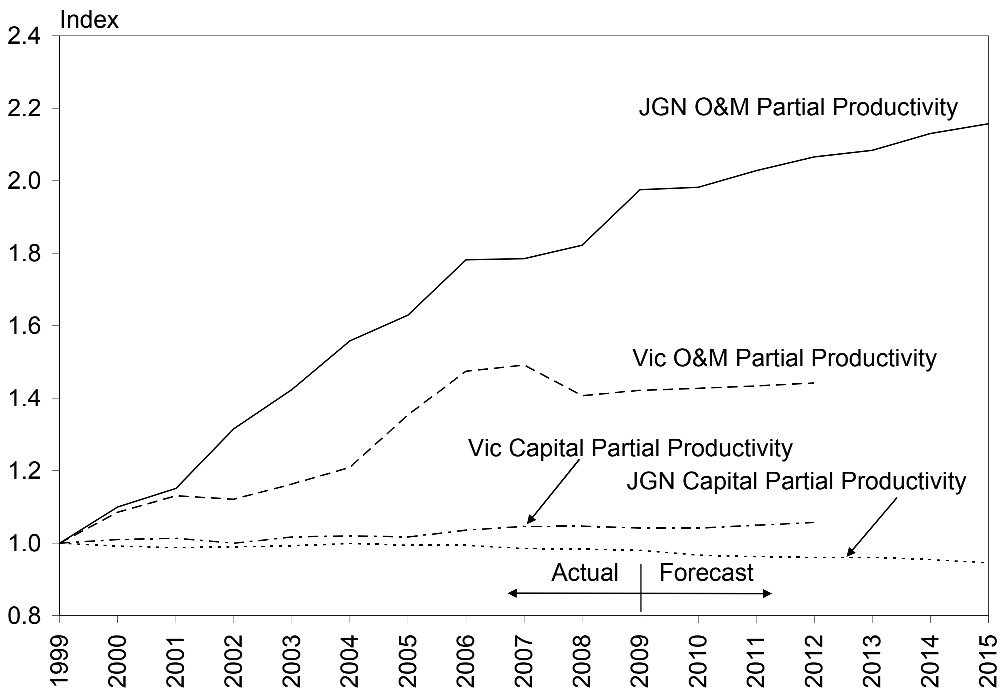

Figure 6-3 shows that JGN's opex partial factor productivity has grown at an average rate of 4.8 per cent per year from 1999 to 2009 and is forecast to grow at 2.1 per cent per year over the next AA period. These rates are significantly higher than those achieved and forecast by the Victorian gas businesses. As Economic Insights note, "the opex PFP growth pattern exhibits the 'convergence effect' we would expect, starting at high growth rates in the early stages of reform tapering off over time to a more sustainable rate reflecting the underlying rate of technical change."[32]

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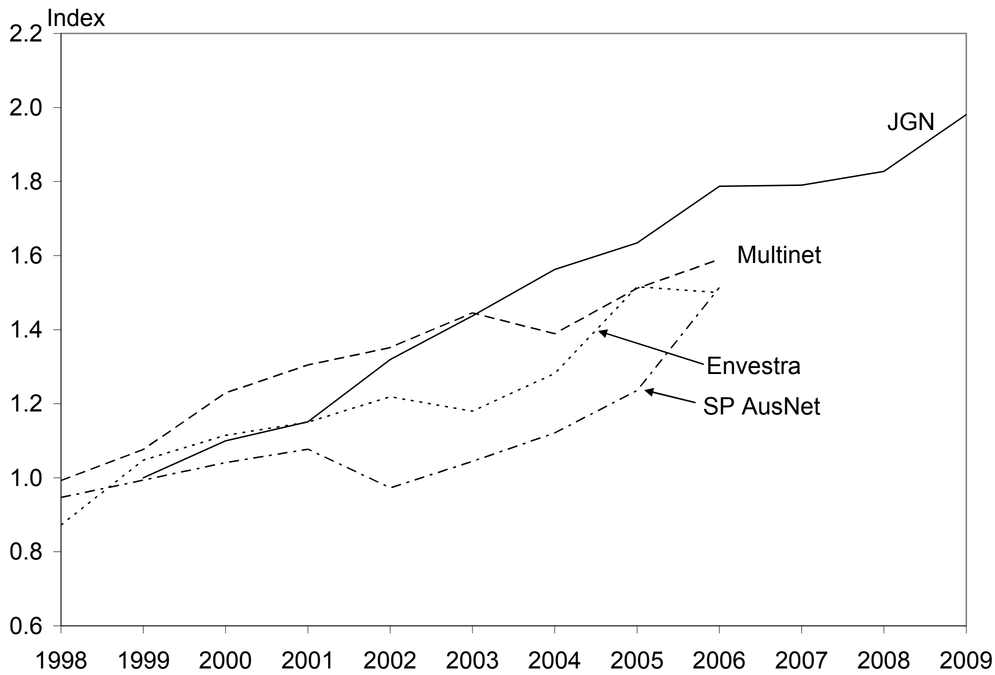
[32] Economic Insights Pty Ltd, *The Productivity Performance of Jemena Gas Networks' NSW Gas Distribution System*, 18 August 2009, p. ii. Appendix 6.7.

JGN's relative level of opex efficiency, as measured by multilateral partial productivity analysis also compares favourably with that of its Victorian peers as illustrated by Figure 6-4 which is also taken from the Economic Insights report.

Figure 6-4: JGN and Victorian gas distributors' multilateral opex partial factor productivity indices, 1998-2009



On this basis, JGN considers its forecasts are consistent with those required to achieve the lowest sustainable cost of service.

6.8 Key performance indicators for the next AA period

NGR 72(1)(f) requires that the AAI for a full AA proposal must include the following:

- the key performance indicators to be used by the service provider to support expenditure to be incurred over the access arrangement period.

This does not refer to either capex or opex specifically, or to any particular KPIs that should be included in the AAI.

JGN proposes to retain the existing distribution KPIs to reflect the reclassification of its trunk pipelines as distribution pipelines. Table 6-14 sets out JGN's proposed KPIs based with outcomes if JGN's demand forecasts and opex forecasts, set out in chapters 5 and 6 respectively, become actual outcomes.

Table 6-14: Proposed KPIs: Operating cost per metre and cost per customer site ($)

	2010-11	2011-12	2012-13	2013-14	2014-15
Operating cost per metre	4.44	4.41	4.52	4.63	4.74
Operating cost per customer site	98.90	95.73	95.70	95.89	96.90

6.9 RIN and rule 72 requirements

Table 6-15 sets out RIN and rule 72 requirements met in chapter 6.

Table 6-15: Summary of RIN responses

RIN/ rule 72 Reference	RIN Requirement	Where addressed in AAI
Opex in the earlier AA period		
RIN 2.2.5.1 Rule 72(1)(a)(i)	Provide in pro forma 6 actuals and estimates of opex by category for each year of the earlier AA period	Table 4-7 Section 4.3 for actuals Sections 6.1, 6.5 and 6.6 for forecast
Forecast opex in the AA period		
RIN 2.3.5.2 (a) Rule 72(1)(e)	Provide in pro forma 6 opex forecasts by category for each year of the access arrangement period	Table 6-6 and Table 6-12. Section 6.6 building blocks regulatory model
RIN 2.3.5.2(b)(i)	Outline and explain the change in opex categories between the earlier access arrangement period and the access arrangement period.	Sections 6.4, 6.5 and 6.6
RIN 2.3.5.2(b)(ii)	Describe and explain the nature of material forecast opex in an opex category. This explanation should also outline if there have been changes to the operations of the pipeline from the earlier access arrangement period that have resulted in material changes to opex category and total opex in the access arrangement period. And define the materiality threshold used	Sections 6.3, 6.4 and 6.5.
RIN 2.3.5.2(b)(iii)	Provide an explanation of how the proposed opex complies with Rule 91, with particular reference to opex identified in (ii.)	Section 6.7

RIN/ rule 72 Reference	RIN Requirement	Where addressed in AAI
RIN 2.3.5.2(b)(iv) Rule 72(1)(e)	Any assumptions used in deriving the forecast opex. Note these may include: • the unit rates used for key items of expenditure, how these have been developed (including source material) and evidence that they reflect efficient costs • specific rates used to derive or extrapolate expenditure estimates (for example, labour and materials) Where relevant provide: • in pro forma 3 the specific rate used in each year of the access arrangement period • whether the rate is in real or nominal terms • how the derivation or extrapolation has been developed (including source material)	Sections 6.3, 6.4, 6.5 and 6.6. Section 6.4.3 Table 6-4, 6-5 Section 6.4.3 Table 6-4, 6-5 Section 6.4.3 Table 9-5
Self-Insurance		
RIN 2.3.5.3 (a)	For each self insured event provide in pro forma 6: • The forecast annual insurance premiums over the access arrangement period	Section 6.5.5. Appendix 6.5: Marsh self insurance report Table 6-6
RIN 2.3.5.3	Provide in the access arrangement proposal submission the following information for each self insured event: • the name and a description of the event • whether the event is in relation to a particular asset or class of assets and, if so, identify those assets • reasons for self insuring the event. If the event has not previously been self insured, reasons why it is now being proposed and how the risk of the event was previously accommodated in the access arrangement. If a proposed self insurance event was previously insured externally, details of existing or previous insurance policies and reasons why external insurance is not relevant in the access arrangement period • details of any quotes obtained from external insurers • full details of how the premiums were calculated, including any underlying assumptions used to derive the premiums • any expert consultant's report relied on by the service provider in deriving the estimates • a resolution (including the date of the resolution) of the service provider's decision	Section 6.5.5. Appendix 6.5: Marsh self insurance report

RIN/ rule 72 Reference	RIN Requirement	Where addressed in AAI
	making body to self-insure the event(s) • details of the administrative arrangements that: – outline how the self insurance risk is to be reported if required under relevant accounting standards in the service provider's audited financial statements or equivalent – outline the procedure for notification and information that will be provided to the AER when the self insurance event occurs.	
Key performance indicators		
Rule 72(1)(f)	The key performance indicators to be used by the service provider to support expenditure to be incurred over the access arrangement period.	Section 6.8

7 Forecast Capital expenditure

This chapter examines JGN's forecast capex, demonstrates how JGN has forecast its costs and describes how these forecast costs comply with the relevant provisions of the NGR. The chapter is structured as follows:

- *Section 7.1 Summary* – provides an overview of JGN's proposed forecast capex requirements over the next AA period
- *Section 7.2 Law and rules requirements* – identifies that JGN's forecast capex must be prudent, accord with good industry practice and provide for the lowest sustainable cost of pipeline services
- *Section 7.3 JGN capital planning* – explains the capital planning process including project identification, the governance processes JGN employs to specify and manage its capital program planning and delivery, the AMP and IT plan (ITP)
- *Section 7.4 Distribution forecast methodology* – outlines how JGN has forecast its network capex using a fit-for-purpose forecasting methodology
- *Section 7.5 JGN capex forecast* – sets out the JGN forecast capex based on its AMP and ITP and escalating cost inputs using the CEG input cost escalators
- *Section 7.6 Compliance with rule requirements* – provides details of the independent expert assessment that JGN's capex forecasts represent those of a prudent service provider acting efficiently in accordance with accepted good industry practice to achieve lowest sustainable costs
- *Section 7.7 Budget approval* – describes process undertaken to approve JGN's budget
- *Section 7.8 RIN and rule 72 requirements* – maps the RIN and NGR rule 72 requirements to the relevant sections, chapters and regulatory models.

7.1 Summary

Over the current AA period JGN has spent almost all its allowed capex.

To maintain the efficiency of its capital delivery program into the future, JGN has established commercial incentivised outsourcing and robust in-house governance to prudently select its investments and minimise its capex costs. These arrangements are discussed in chapter 3.

JGN's forecast capex over the next AA period is shown in Table 7-1.

Table 7-1: JGN forecast capex

Capex	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Total	173.1	167.1	167.8	181.0	196.2	885.2

JGN's forecast capex for the next AA period is based on its AMP and ITP. It reflects a program designed to enable JGN's network and IT to operate at an acceptable level of risk including:

- ongoing renewal and upgrade of mains and services, addressing priority areas with high leakage rates and capacity constraints maintained at current levels, maintaining asset safety and reliability at current levels

- capacity development to manage demand growth with system average interruption duration index (**SAIDI**) and customer hours off supply (**CHOS**) maintained at current levels or lower

- renewal and upgrade of ageing facilities considering upstream operating pressure upgrades, standardisation, OH&S risks, spares and inventory control, capacity constraints, integrity and compliance with technical regulatory requirements

- robust IT program that supports business and market requirements and optimises IT opex.

JGN considers its forecast expenditure complies with the NGR—a view supported by independent expert opinion reports from KPMG for IT capex and PB for network capex.

Accordingly, JGN considers that its forecast capex represents those of a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services.

JGN notes that its capital program requires a significant cash outlay over the next AA period totalling $885.2 million. This extensive capital program is made possible by JGN's proposed cost of capital discussed in chapter 9 and proposed price path discussed in section 13.8. Together these provide the necessary cash flow to sustain this prudent investment.

7.2 Law and rules requirements

The NGR requirements for capex information include the following:

- must provide capex (by asset class) over the earlier AA period (rule 72(1)(a)(i)) which JGN has addressed in section 4.4
- must provide a forecast of conforming capex for the period and a basis for the forecast (rule 72(1)(c)(i)) which JGN sets out in this chapter.

Conforming capex must meet the following criteria:

- capex must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services (rule 79(1))
- the capex must be justifiable on a ground stated in sub rule 79(2).

Conforming capex is justifiable if:

- the overall economic value of the expenditure is positive; or
- the present value of the expected incremental revenue to be generated as a result of the expenditure exceeds the present value of the capex; or
- the capex is necessary
  - to maintain and improve the safety of services
  - to maintain the integrity of services
  - to comply with a regulatory obligation or requirement
  - to maintain the service provider’s capacity to meet levels of demand for services existing at the time the capex is incurred (as distinct from projected demand that is dependent on an expansion of pipeline capacity)
- the capex is an aggregate amount divisible into two parts, one referrable to a purpose referred to in paragraph 79(2)(c), and the former is justifiable under paragraph 79(2)(b) and the latter under paragraph 79(2)(c).

Rule 79 (6) limits the AER’s discretion under these rules.

7.3 JGN capital planning

JGN commissioned JAM to prepare two capital plans, which form the basis of its capex forecasts. These are its AMP and its ITP. JGN management engaged extensively with all elements of its business operations during the development of these plans to ensure they accorded with its commercial and service performance directions for the network.

JGN's capital planning framework defines the planning process for individual projects, within a two- to three-year timeframe as well as for the overall project program over a five-year cycle.

7.3.1 Project identification

JGN capital projects are identified through

- annual review of network performance and available capacity (through winter field monitoring/gauging and network modelling)
- planning to meet long-term capacity requirements
- planning to maintain long-term asset and integrity
- ongoing assessment of customer connection requests.

These projects are then incorporated into the AMP and ITP, prioritised based on a number of factors, including commercial, regulatory, environmental, and safety risks, as well as the intangible, such as loss of reputation. These are then ranked into the five-year AMP and where relevant, the ITP.

7.3.2 Project governance

JGN employs a strong capital project governance regime to manage project planning, approval and delivery by JAM. This governance regime include a project gating process as well as overall program planning and control through the AMP and ITP.

JGN's project gating process provides project governance by JGN throughout the life of all its projects, from inception through to delivery and project close-out.

The gating process consists of seven gates, with the first four gates (gates 1 to 4) governing project initiation, planning and design up to the stage where JGN approves the business case. Gates 5 to 7 apply to the construction, handover and close-out phases of the project. Project cost estimates are produced at each of the first three gates, with narrowing order of accuracy, reflecting the incremental development of the project.

JGN's AMP includes projects at various gates. Those in the earlier years of the next AA period are generally at more advanced gates than those in the later years.

Table 7-2: Capital project governance gates

Gate	Information JAM provides to JGN	JGN's approval
1. Requirement	JAM: • defines the project need • identifies and assesses options • provides initial cost estimates as 'rules-of-thumb'.	JGN confirms there is a requirement and provides approval to prepare either a feasibility case (gate 2) or to prepare a committed estimate (gate 3).
2. Feasibility	JAM provides an assessment of the project's feasibility and a more refined cost estimate.	JGN provides approval to prepare a committed estimate and release of funds for detailed design/long lead items as appropriate.
3. Committed estimate	JAM provides a committed cost estimate, along with a review of the project scope, cost, time and quality deliverables that will be included in the final business case.	JGN provides approval to prepare a detailed business case.
4. Business case	JAM provides a detailed assessment of options, economic evaluation and project benefits.	JGN provides approval of the business case and approval to commence preparation of construction related documents and release of funds for construction.
5. Construction	JAM provides a review approved business case and construction related documents.	No action required.
6. Handover	JAM provides handover of project between construction and operation groups.	No action required.
7. Completion	JAM undertakes project and financial close-out of project.	JGN confirms project completion and close-out.

7.3.3 Asset management plan

Asset management strategy

JGN's business drivers reflect the goals and concerns that JGN and certain external stakeholders have for the asset. These drivers directly influence the direction in which JGN wishes to take the business.

JGN has specified the business objectives for the AMP to reflect the relative importance it places on different business drivers. The JGN business objectives, as communicated by JGN and recorded in the AMP are that:

- JGN intends to hold the assets for more than five years

- JGN intends to meet all regulatory requirements, with special emphasis on safety and environmental requirements
- JGN intends to minimise capex through an active risk management process
- JGN intends to optimise the cost effectiveness of meeting regulatory performance targets
- JGN wants to be known as a reliable deliverer of energy through its infrastructure
- JGN will respond to customer growth requirements subject to economic connection of supply
- maintaining cash flow is critical to overall business planning
- the asset is to be maintained and upgraded so that average remaining life continues to reduce gradually
- operation of the network will not negatively impact Jemena's reputation.

Table 7-3 summarises these business objectives into key capex planning drivers.

Table 7-3: Key drivers and description

Driver	Description	JGN Objective
Risk exposure	Safety, reliability	• Minimise capex through an active risk management process
Operational efficiency	Maintenance, performance output, operating costs	• Respond to customer growth requirements subject to economic connection of supply
Network expansion arising from housing growth	Provision of gas network facilities to new housing estates	• To extend its network to meet the needs of new housing estates developed within JGN's network footprint
Reputation	Customer impression, quality, public image	• Seen as a reliable supplier of energy through its infrastructure • Operation of the network will not negatively impact JGN's reputation
Capital value	Capital requirement, life expectancy, reliability	• The asset is to be maintained and upgraded so that average remaining life continues to reduce gradually • Ensure that assets survive for at least five years
Revenue	Commercial, regulatory, marketing, for utilisation, pricing	• Maintain cash flow is critical to overall business planning

Driver	Description	JGN Objective
Compliance	Technical, regulatory, environmental, safety	• Meet all regulatory requirements including those set out in Table 1-2, with special emphasis on safety requirements • Optimise the cost effectiveness of meeting regulatory performance targets
Environmental	Sustainable development, minimal impact	• Ensure that landowners whose properties contain JGN assets have environmental and public safety protection

Asset management plan process and coverage

An AMP is developed annually for the JGN network. It outlines the proposed long-term technical management strategy for JGN's network. The AMP focuses on achieving an optimal balance between the key elements of asset management—service levels, cost and risk.

The AMP details the current and proposed strategies for the effective management of the network. As a result, the AMP is used as a platform for approval of proposed work programs by providing a forum for discussion of the asset management options available. It sets the five year work program within which JGN considers specific annual projects for review and final approval consistent with the later stages of the gating process described in Table 7-2.

The AMP covers management of the following assets:

- trunk mains and facilities
- primary mains, facilities and services
- secondary mains and services
- low and medium pressure mains and services
- pressure regulating stations (all pressures)
- meters and meter sets
- SCADA, communications and monitoring.

Key AMP projects for 2010-11 to 2014-15

The key network projects for the next AA period are:

- *Renewal of the Wakehurst Parkway capacity development project* - providing capacity for growth and supply reliability to the Northern Beaches area, this project extends the secondary main along the Wakehurst

Parkway, improving supply to downstream medium pressure networks, and represents a major capacity enhancement for the area that has been deferred with the implementation of minor works and operational measures.

- *Penrith-Emu Plains primary main and primary receiving station facility* - providing capacity for growth and supply reliability to the Blue Mountains secondary network, this project will extend the primary main from Penrith, crossing the Nepean River, and install a new PRS facility at Emu Plains.

- *Packaged off-take station upgrade for increased MSP operating pressures in MSP laterals* – increase in upstream pressure for Marsden to Dubbo and Junee to Griffith laterals is scheduled to occur in a phased manner over the next few years, as advised by APA, resulting in the maximum allowable operating pressure (**MAOP**) of those POTS being less than the operating pressure of the pipeline and requiring upgrades are for compliance to new MAOP.

7.3.4 Information technology plan

IT strategy

JGN's IT plan reflects the following business imperatives:

- minimising the risk of systems disruption and failures

- providing systems that have a total cost of ownership and operation over their useful life that is economically effective, balances risk and costs

- supporting continuous improvements to services

- introducing innovation to users and customers, the business and the energy industry

- establishing forward planning upgrades at regular intervals to ensure JGN and JAM can make sufficient financial and resource provisions with sufficient lead times.

IT plan

JGN has commissioned JAM to prepare its ITP for the next AA period. The plan incorporates the IT capex investments and projects in 2008-09, and those planned for 2009-10 that will be operable in the next AA period.

The IT capex forecast for the next AA period provides a balanced mix of new systems applications, old legacy systems replacement, systems upgrade and small scale continuous improvements to enable major business improvements.

Key ITP projects for 2010-11 to 2014-15

The forecast $94.67 million IT capex spend over the next AA period overcomes the historical under investment in IT systems as JGN went through a long and highly disruptive period of ownership changes. It also allows JGN to maintain opex in the next AA period at close to current levels in real terms, subject to step changes for additional functions particularly those related to the STTM and escalation for changes to input costs.

The key IT programs and projects for the next AA period are:

- *GASS replacement* – replacing the 25 year old in-house GASS (a primary metering, billing, and works management IT system used by JGN to manage its network business) application with a combination of new SAP works management modules, market sourced metering and billing application suite along with some in house development by JAM's sub-contractor EBS

- *SAP replacement* – replacing the 1998 implemented SAP 4.6 modules with the new SAP 6.0 modules

- *GIS introduction* – introducing a geographic information system (**GIS**) into JGN for the first time, replacing current manual and scanned images basic technologies that have no real time or process efficiencies

- *Security camera installation* – implementing security cameras to continue improving security for critical industry assets that are subject to malicious threats and damage

- *Development of management systems* – upgrading network design systems, introducing design and drawing document management systems and contributing to the process re-engineering of network management processes.

7.4 Distribution forecast methodology

JAM has adopted a fit-for-purpose forecasting methodology for capex forecasting. This employs different forecasting methods for different categories of capex that reflect the nature of capex projects or activities within those categories.

IJAM initially forecast all capex costs in 2008-09 dollars, and then adjusted them for the real input cost escalators determined by CEG and for forecast CPI inflation, in accordance with instructions from JGN. JGN's escalators are described in section 6.4 and are detailed in Appendix 6.4. JGN's CPI inflation forecasting methodology and resulting forecast set out in section 9.7.1.

7.4.1 Network capital expenditure

Table 7-4 summarises JGN's methods for forecasting network capex and the rules upon which it has relied for capex justification. In those cases where JGN cites rules 79(2)(c)(i) or 79(2)(c)(iii), the reference is to the requirements of the Gas Supply (Safety and Network Management) Regulation 2008 and, where applicable, the Pipelines Regulation 2005 and the pipeline licences held by JGN in respect of the trunk pipelines. Those instruments impose obligations on JGN that are directed at ensuring that JGN develops, maintains and operates a safe gas network and licensed pipelines, and require it to design construct and operate its assets in accordance with applicable standards.

Expenditure on meter renewal and upgrade, where justified by rule 79(2)(c)(iii), is required to meet obligations imposed by the Gas Supply (Gas Meters) Regulation 2002. Expenditures justified on the basis of rules 79(2)(c)(ii) or 79(2)(c)(iv) are required to ensure that JGN can continue to deliver services in accordance with contracted terms and conditions.

Table 7-4: Forecast methods for network capex

Program	Rule 79(2) justification	Methodology and key assumptions
Market Expansion	79(2)(b)	Market expansion activities are considered high volume routine activities. Capex is forecasted on the basis of forecasted volumes of new connections and unit rates. NIEIR forecasts the annual volumes of new connections for all market types following historical trends (see chapter 5). Forecast unit rates are based on historical actual rates from the current AA period, and the forecasted 2009-10 rates.
Growth capacity development	79(2)(c)(ii) and (iv)	Projects for capacity development are identified for inclusion in the AMP and capex forecasts through various planning, monitoring, validating and risk assessment activities. JGN forecasts the capital costs of these projects using three methods: • Desktop estimate based on average units rates from comparable recent projects • Feasibility estimate that updates the desktop estimate using identified features of the project, the JAM Pricing Model and information from site visits, including estimates from external quantity surveyors • Committed estimates that include information from contractors and tenders. JGN also includes an annual budget allocation for a number of small projects identified after the approval of the AMP each year. For this purpose, a small budget allocation of $100,000 is included for each year. Overall, external quantity surveyors estimate the costs for about 90 per cent of projects using the JPM, while the average unit rates are used for the remaining 10 per cent. Committed estimates are developed for projects prior to final approval/release of funds.

Program	Rule 79(2) justification	Methodology and key assumptions
Mains and services renewal	79(2)(c)(i) and (ii)	Mains and renewal capex includes budget allocations for renewal activities as well as projects identified for larger areas. Budget allocations include: • Ad-hoc renewal of mains and services; localised renewal of sections of main and associated services that pose unacceptable risk or have reached the end of their economic life (specific projects are identified each year) • Ad-hoc renewal of individual services that pose unacceptable risk or have reached the end of their economic life. Forecasts for budget allocations are based on levels of historic renewal activities and current policies and procedures. Based on this information, JGN considers renewal activities will rise in the future. Forecasts for larger projects are based on historic proposals and average unit rates from comparable recent projects. Committed estimates are developed for projects prior to final approval / release of funds.
Mines subsidence	79(2)(c)(i) and (ii)	Forecast capex is based on the current scope of proposed activities as at April 2009 and includes current estimates from JAM. Committed estimates are developed for projects prior to final approval / release of funds.
Stay in business facilities and SCADA	79(2)(c)(ii) and (iv)	JGN undertakes stay in business capex to maintain the integrity of services, and maintain capacity to meet demand from existing customers. Projects are identified for inclusion in the AMP and capex forecast through various planning, monitoring, risk and engineering assessment activities. JGN forecasts the capital costs of these projects using three methods: • Desktop estimate based on average units rates from comparable recent projects • Feasibility estimate that updates the desktop estimate using identified features of the project, the JAM Pricing Model and information from site visits, including estimates from external quantity surveyors • Committed estimates that include information from contractors and tenders. JGN also includes an annual budget allocation for a number of small projects identified after the approval of the AMP each year. Committed estimates are developed for projects prior to final approval/release of funds.

Program	Rule 79(2) justification	Methodology and key assumptions
Meter renewal and upgrade	79(2)(c)(ii) and (iii)	Like market expansion activities, planned meter renewals and upgrades are considered high volume routine activities and estimated based on forecast volumes and unit rates. Forecast volumes are based on the life expectancy of various meter types, based on data extracted from GASS for current assets in service. Forecast unit rates are based on historic actual rates from the current AA period and the current 2009-10 rates.
Government authority work	79(2)(c)(iii)	JGN is often required by government authorities to move its mains. JGN forecasts a cost of $500,000 per year (real $2008) based on the historical trend. Committed estimates are developed for projects prior to final approval / release of funds.

Source: JAM.

7.4.2 Non-network forecast methodology

Table 7-5 summarises JGN's methods for forecasting non-network capex and the rules upon which it has relied for capex justification. Expenditures justified on the basis of rule 79(2)(c)(iv) are required to ensure that JGN can continue to deliver services in accordance with contracted terms and conditions.

Table 7-5: Forecast methods of non-network capex

Program	Rule 79(2) justification	Methodology and key assumptions
Motor vehicles	79(2)(c)(iv)	JGN has an aging fleet of motor vehicles. Its forecast capex assumes: • rolling replacement of fleet based on a combination of vehicle age and actual/expected km • replacement occurs on the registration renewal date • budget costs by vehicle type in $2008. The forecast is based on individual vehicles summarised for vehicle categories (e.g. trucks, trailers and passenger vehicles) on an annual basis.
Leasehold improvements, buildings and land	79(2)(c)(iv)	• Forecast capex assumes leasehold improvements including relocation of North Parramatta Control Centre to the Sydney Olympic Park site
IT and communications	Various as set out In Appendix 7.2 including 79(2)(a) and (c)	JAM has forecast IT capex on a project specific basis for the following key IT projects: • Jemena transition projects • corporate, financial & office systems • business intelligence and management reporting • document and records management - electronic content management

Program	Rule 79(2) justification	Methodology and key assumptions
		• geographic information system (GIS) • supervisory control and data acquisition (SCADA) • distribution network and load management systems • market services and risk management • gas network services delivery • customer service, billing and metering GASS replacement • IT infrastructure
Planned fixed and mobile plant and equipment	79(2)(c)(iv)	JAM has forecast this capex based on recent unit rates and recent expenditure for: gas leak surveyor units, pipe locators, pipeline current mappers, CP fault finding tools, oscilloscopes, druck gauges, pressure pot sand blasting cabinets, high pressure purge burners, hydraulic squeezers, motor drive pump for high pressure hot tapping drill, plidco clamps and seals, air compressors, tippers, excavators and trailers.

7.5 Forecast capex

Various instruments including the AER's RIN, the IPART requirement for an asset register and the AER's AA consolidation direction require JGN to report its capex against different categorisations. The remainder of this chapter reports JGN's forecast capex based on market expansion, system reinforcement/ renewal/replacement, and non-system asset (also referred to as non-distribution asset) categories. Appendix 7.3 provides further categories of the same capex forecasts.

Table 7-6 summarises JGN's forecast capex which complies with the NGR.

Table 7-6: Forecast capex over the next AA period

Capex	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Market expansion	64.7	75.6	80.7	76.8	73.2	371.0
System reinforcement/ renewal / replacement	82.7	71.4	69.0	69.9	88.0	381.0
Non-system assets	25.7	20.1	18.1	34.2	35.0	133.2
Total	**173.1**	**167.1**	**167.8**	**181.0**	**196.2**	**885.2**

Sources: JAM, 2009, *Jemena Asset Management Plan for the Jemena JGN (NSW) Gas Network 2009-10 – 2014-15.*

JAM, 2009, *Jemena Asset Management: 2010-11 – 2014-15 Information Technology Strategy and Asset Management Plan for Jemena Gas Networks (NSW).*

7.6 Rule compliance

JGN considers that its planning, governance and outsourcing arrangements together with its reliance on expert determined input cost escalators provide demand forecasts that comply with the NGR.

In accordance with good industry practice, JGN has sought independent verification of this.

JGN commissioned two independent expert reports to review its capex programs proposed by JAM. These reviews assessed compliance with the NGR requirements—PB (AMP capex) and KPMG (ITP capex).

7.6.1 Expert review of network capex

PB reviewed the capex and asset management practices of JAM to:

- review JGN's proposed network capex forecast over the next AA period against s79(1) of the NGR that assesses whether it is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing service
- review JGN's proposed network capex forecast to assess whether it is justifiable in accordance with NGR s. 79(2) of the National Gas Rules
- assess compliance with rule 74
- suggest further improvements where PB considers them necessary or desirable.

Specifically, PB assessed the JGN network for the:

- prudency of capex for the period from 2005-06 to 2009-10 in order to determine compliance with rule 79 of the NGR
- effectiveness of JGN capital planning practices, the prudence of planning outcomes and the reasonableness of estimates of capex over the next AA period in order to determine compliance with rules 74 and 79 of the NGR
- benchmarking of the network capex against key performance indices from other gas and electricity distribution businesses in order to determine compliance with rule 74 of the NGR.

PB concluded that:

> 'In undertaking detailed review of projects forecast within the 2010-2015 Access Arrangement period, PB found that the proposed expenditure in all projects reviewed is considered Conforming Capital Expenditure, in compliance with National Gas Rule 79.' [33]

7.6.2 Expert review of IT capex

KPMG was engaged by JGN to review its IT capex program and strategy. Specifically, KPMG was asked to:

- review JGN's proposed IT capex forecast over the next AA period against rule 79(1) of the NGR that assesses whether it is such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing service
- review JGN's proposed IT capex forecast to assess whether it is justifiable in accordance with rule 79(2) of the NGR.
- Provide accurate high level estimates of IT projects suited for participants in the energy industry based on the best available information at the current point in time.

KPMG concludes that:

> 'Based on our analysis to date, it appears that the IT capex outlined in the IT program is reasonably prudent and efficient and therefore complies with NGR rule 79(1).' [34]

Commercial in confidence

[33] Parsons Brinckerhoff Australia Pty Ltd, *2010-11 to 2014-15 Jemena Gas Networks Access ArrangementRreview – Review of JGN Capital Expenditure*, August 2009, p. vi. Appendix 7.4.

[34] KPMG, *JGN Gas Networks (NSW) – IT Capital Expenditure Assessment, Final Report*, 15 August 2009, p. 31. Appendix 7.5.

7.8 RIN and rule 72 requirements

Table 7-7 sets out RIN and rule 72 requirements met in chapter 7.

Table 7-7: Summary of RIN responses

RIN/rule 72 reference	RIN requirement	Where addressed in AAI
Forecast conforming capex in the access arrangement period		
RIN 2.3.1.7 Rule 72(1)(c)	(a) Provide in pro forma 1 amounts by asset class for each year of the access arrangement period for forecast conforming capex (b) Provide in pro forma 3 the extrapolation rates, where applicable, used in deriving forecast conforming capital (c) The nature of forecast conforming capex projects or programmes material to an asset class including a brief description of the capex and the location on the distribution pipeline or network	Regulatory asset base roll forward model, Table A7.3.1 and A7.3.2, chapter 8 Building blocks regulatory model, chapter 8
RIN 2.3.1.7 Rule 72(1)(c)	(d) Any assumptions used in deriving the forecast conforming capex Note these may include: - the unit rates used for key items of expenditure, how these have been developed (including source material) and evidence that they reflect efficient costs - specific rates used to derive or extrapolate e expenditure estimates (for example, labour and materials) Where relevant provide: - in pro forma 3 the specific rate used in each year of the access arrangement period - whether the rate is in real or nominal terms - how the derivation or extrapolation has been developed (including source material)	Section 7.4. Appendix 6.4: CEG input cost escalators Table 7-4
RIN 2.3.1.7	(e) Any relevant internal decision making documents including business cases, feasibility studies, forecast demand studies and internal reports and the date of board resolution/management decisions relating to approval of the forecast capex. Any other internal or external documentation or models to justify the forecast conforming capex (f) Details as to whether the forecast conforming capex is to be funded by parties other than the asset owner and details of contractual agreements with parties where capital contributions are made by users to new capex as subject to Rule 82 (g) An explanation of how the forecast capex conforms with the criteria under Rule 79(1) (h) The reason why the forecast capex is justifiable under Rule 79(2). In explaining why the forecast capex is justifiable outlining, which sub rule in 79(2) is relied on	Section 7.7 Section 8.6 Section 7.6. Appendix 7.4: PB review of AMP capex As above
RIN 2.3.1.7	If Rule 79(2)(a) is relied on to justify new capex provide in the access arrangement proposal submission:	N/A

RIN/rule 72 reference	RIN requirement	Where addressed in AAI
	(i) An explanation and quantitative analysis to demonstrate how the capex is justifiable under Rule 79(2a) (j) An outline of the nature and quantification of the economic value that directly accrues to the service provider, gas producer, users and end users will need to be outlined to address Rule 79(3)	
RIN 2.3.1.7	If Rule 79(2)(b) is relied on to justify new capex provide in the access arrangement proposal submission: (k) Explanation of how the capex is justifiable under Rule 79(2a). The explanation (including relevant information and documentation) will need to outline i. The incremental service or services with reference also to Rule 79(4)(a) ii. The incremental revenue, with reference to the derivation of incremental revenue in Rule 79(4)(b) iii. The incremental expenditure with reference to Rule 79(4)(b) iv. Quantitative analysis that demonstrates the capex is justifiable under Rule 79(2a). Showing: - The present value of expected incremental revenue and how it is determined consistent with sub rules 79(4)(a) and 79(4)(b) - Discount rate used to determine is equal to the rate of return implicit in the reference tariff - The present value of the expected incremental expenditure	N/A
RIN 2.3.1.7	If Rule 79(2)(c)(i)-(iii) is relied on to justify new capex provide in the access arrangement proposal submission: (l) The relevant statutory obligation or technical requirement and the relevant authority or body enforcing the obligation or requirement (m) An explanation of how the forecast capex satisfies the relevant statutory obligation or technical requirement (n) Supporting technical or other external or internal reports about how the forecast capex complies with the relevant statutory obligation or technical requirement	Section 7.6. Appendix 7.4: PB review of AMP capex
RIN 2.3.1.7	If Rule 79(2)(c)(iv) is relied on to justify new capex provide in the access arrangement proposal submission: (o) An explanation of the change in demand for existing services necessitating the new capex, including a measure of the change in demand (p) Reports or other information and documentation that supports how the forecast capex will meet the increase in demand for existing services	Section 7.6. Appendix 7.4: PB review of AMP capex

8 Regulatory Asset Base

The NGR require a roll forward of the RAB to determine an allowance for the return on and of capital.

This chapter sets out how JGN proposes to roll forward this asset base taking into account its capex, disposals and depreciation over the current AA period.

This chapter is structured as follows:

- *Section 8.1 Summary* – provides an overview of JGN's proposed RAB roll forward over the next AA period
- *Section 8.2 Law and rules requirements* – sets out the rule requirements which JGN must comply with in rolling forward its RAB
- *Section 8.3 Opening capital base for the current AA period* – provides details on JGN's opening RAB in the current AA period
- *Section 8.4 Closing capital base for the current AA period* – sets out the closing RAB for the current AA period
- *Section 8.5 Projected capital base in the next AA period* – details the projected RAB for the next AA period
- *Section 8.6 Capital contributions* – sets out JGN's capital contributions to be deducted from the RAB roll forward
- *Section 8.7 Disposals* – sets out JGN's disposals or 'scrapings' to be deducted from the RAB roll forward
- *Section 8.8 Capital redundancy policy* – explains JGN's capital redundancy policy
- *Section 8.9 RIN and rule 72 requirements* – maps the RIN and NGR rule 72 requirements to the relevant sections, chapters and regulatory models.

8.1 Summary

JGN has determined that the combined total of its RAB at 1 July 2010 is $2,367 million ($nominal) and is forecast to be $3,042 million at 30 June 2015 ($nominal), as shown in Table 8-1. This is based on JGN's opening RAB in the current AA period adjusted for actual and forecast capex, contributions and disposals as well as $3.44 million of reused redundant assets from the southern trunk required to accommodated the unconstrained design of the STTM.

Table 8-1: Forecast value of RAB at 30 June 2015 ($nominal)

Asset class	Closing RAB at 30 June 2015
Wilton-Wollongong trunk	12.98
Wilton-Newcastle trunk	145.16
NSW distribution network	2,883.37
Combined total	**3,041.51**

In 2005 IPART agreed to JGN's proposal to treat the four pipelines that comprised its NSW network as a single covered pipeline for the purposes of the gas code and AA. In its decision on the 2005 AA, IPART required JGN to maintain separate capital bases for each of the Wilton to Newcastle and Wilton to Wollongong transmission pipelines and the distribution system, in addition to the aggregated capital base.[35] The AER has imposed similar terms in its AA consolidation direction. JGN has prepared its RAB roll forward by these three capital bases.

8.2 Law and rules requirements

JGN has calculated the opening capital base as at 1 July 2010 by rolling forward the opening capital base from the current regulatory period as at 1 July 2005, in accordance with rule 77(2) which states:

(2) If an access arrangement period follows immediately on the conclusion of a preceding access arrangement period, the opening capital base for the later access arrangement period is to be:

- the opening capital base as at the commencement of the earlier access arrangement period (adjusted for any difference between estimated and actual capex included in that opening capital base)

plus:

- conforming capex made, or to be made, during the earlier access arrangement period

plus:

- any amounts to be added to the capital base under rule 82, 84 or 86

[35] AER letter to JGN dated 5 June 2009.

less:

- depreciation over the earlier access arrangement period (to be calculated in accordance with any relevant provisions of the access arrangement governing the calculation of depreciation for the purpose of establishing the opening capital base)

plus:

- redundant assets identified during the course of the earlier AA period
- the value of pipeline assets disposed of during the earlier AA period.

8.3 Opening capital base for the current AA period

In its 2005 decision[36], IPART required AGLGN, now JGN, to make the following amendments to its proposal:

> **Amendment 9 - Regulatory asset register (chapter 7)**
>
> AGLGN must ensure that its regulatory asset register includes information on the rolled forward capital base at 1 July 2005 consistent with the values set out in Amendment 10 of this final decision.
>
> **Amendment 10 - Rolled forward capital base (chapter 7)**
>
> The proposed access arrangement must be amended so that the capital base used to determine total revenue and reference tariffs complies with the values set out in Tables 7.10 to 7.17 [of the final decision]

Tables 7.5 and 7.10 to 7.13 in the final decision included total capex of $426.7 million ($nominal) for the period to 30 June 2005 which IPART determined met the requirements of the Code:

> The Tribunal's findings on the total capex over the expected term of the current access arrangement are summarised in Table 7.5. The Tribunal requires AGLGN to include only the expenditure shown on this table as meeting the Code requirements in the capital base, as set out in 7.7 below. [37]

Accordingly, "[adjustments] for any difference between estimated and actual capex included in [the] opening capital base" (rule 77(2)(a)) are nil. This means that the

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[36] IPART Final Decision, *Revised Access Arrangement for AGL Gas Networks*, April 2005, pp iii-vi, and 86.

[37] IPART Final Decision, *Revised Access Arrangement for AGL Gas Networks*, April 2005, p. 62.

closing value of the capital base as at 30 June 2005 is as determined by IPART and shown in Table 8-2.

Table 8-2: JGN's closing RAB as at 30 June 2005 ($nominal)

Asset class	Closing RAB 30 June 2005
Wilton-Wollongong trunk	8.5
Wilton-Newcastle trunk	124.2
NSW distribution network	1,832.8
Combined total	**1,965.5**

8.4 Closing capital base for the current AA period

JGN proposes to account for inflation by indexing the capital base. This is consistent with the approach taken in past revisions of JGN's AA, with the NGR and with the precedent set in the majority of Australian regulatory decisions. Therefore, JGN has adjusted its capital base as follows:

capital base = opening capital base + indexation at CPI + conforming capital expenditure – depreciation – capital contributions + conforming assets from speculative investment account – redundant assets + re-used redundant assets – asset disposals[38]

The following projections of the capital base are based on actual data for capex, capital contributions and asset disposals for the years 2005-06, 2006-07 and 2007-08 and up to June 2009 for 2008-09, and forecast data thereafter. In addition:

- economic and remaining asset lives are as presented in section 10.3
- consumer price index values are as set out in Table 8-3.

Table 8-3: Increase in consumer price index

Financial Year	Annual increase in the consumer price index (per cent)
2006 actual	3.98
2007 actual	2.07
2008 actual	4.51
2009 actual	1.46
2010 forecast	2.50

[38] NGR rule 77.

Notes: Values up to 2009 are year on year CPI inflation for the year to June for 8 capital cities as published by the Australian Bureau of Statistics. The value for 2010 is as forecast by the Reserve Bank of Australia in its May 09 *Monetary Policy Statement*.

Source: Australian Bureau of Statistics and Reserve Bank of Australia.

In rolling forward the capital base to 2010, JGN has not included any conforming assets from a speculative investment account or classified any assets as redundant assets. However, as described in section 8.5 below, JGN does propose to classify as re-used redundant assets, that part of the value of the Wilton to Wollongong pipeline that IPART determined to be redundant in its 2005 Final Decision.

JGN has deducted forecast depreciation in rolling forward its capital base from 2006 to 2010 in accordance with clause 3.1(b) of its current AA.

Table 8-4 to Table 8-7 set out JGN's roll forward of the combined total capital base and three covered pipelines over the current AA period.

Table 8-4: Roll forward of combined total capital base over current AA period ($nominal)

Details	2005-06	2006-07	2007-08	2008-09	2009-10
Opening balance	1,965.5	2,051.9	2,132.3	2,240.3	2,282.1
Add capex	86.3	118.7	99.7	97.5	113.6
Add revaluation of assets	115.3	63.6	144.0	49.9	58.4
Less depreciation	103.2	93.7	126.2	99.2	84.6
Less capital contributions	6.2	4.3	7.8	6.0	3.6
Less disposals	5.7	3.9	1.7	0.3	2.5
Add reused redundant assets (end year)	0.0	0.0	0.0	0.0	3.4
Closing balance	2,051.9	2,132.3	2,240.3	2,282.1	2,366.9

Notes: Values for 2008-09 are estimates for the year based on actual data to April 2009. Values for May and June 2009 and all of 2009-10 are forecast. JGN has derived historical amounts from the regulatory asset register that it has maintained in accordance with section 9.1 of its current AA. These notes apply to the following three tables also.

Table 8-5: Roll forward of Wilton to Wollongong trunk pipeline capital base over current AA period ($nominal)

Details	2005-06	2006-07	2007-08	2008-09	2009-10
Opening balance	8.5	8.7	8.7	8.9	8.8
Add capex	0.0	0.0	0.0	0.0	0.0
Add revaluation of assets	0.6	0.3	0.7	0.2	0.2
Less depreciation	0.4	0.3	0.5	0.3	0.3
Less capital contributions	0.0	0.0	0.0	0.0	0.0
Less disposals	0.0	0.0	0.0	0.0	0.0
Add reused redundant assets (year end)	0.0	0.0	0.0	0.0	3.4
Closing balance	8.7	8.7	8.9	8.8	12.3

Table 8-6: Roll forward of Wilton to Newcastle trunk pipeline capital base over current AA period ($nominal)

Details	2005-06	2006-07	2007-08	2008-09	2009-10
Opening balance	124.2	126.7	126.9	130.1	129.4
Add capex	0.0	0.0	0.0	0.0	0.4
Add revaluation of assets	7.4	4.0	8.8	3.0	3.2
Less depreciation	4.8	3.8	5.7	3.7	3.1
Less capital contributions	0.0	0.0	0.0	0.0	0.0
Less disposals	0.0	0.0	0.0	0.0	0.0
Add reused redundant assets (year end)	0.0	0.0	0.0	0.0	0.0
Closing balance	126.7	126.9	130.1	129.4	129.9

Table 8-7: Roll forward of NSW distribution system capital base over current AA period ($nominal)

Details	2005-06	2006-07	2007-08	2008-09	2009-10
Opening balance	1,832.8	1,916.5	1,996.7	2,101.3	2,144.0
Add capex	86.3	118.7	99.7	97.5	113.1
Add revaluation of assets	107.3	59.3	134.5	46.7	54.9
Less depreciation	98.0	89.6	120.0	95.2	81.2
Less capital contributions	6.2	4.3	7.8	6.0	3.6
Less disposals	5.7	3.9	1.7	0.3	2.5
Add reused redundant assets	0.0	0.0	0.0	0.0	0.0
Closing balance	1,916.5	1,996.7	2,101.3	2,143.9	2,224.7

The closing balance values for 2009-10 constitute the opening capital base for the next AA period.

8.5 Projected capital base in the next AA period

The projected capital base in the next AA period is set out in Table 8-8, Table 8-9, Table 8-10 and Table 8-11.

Table 8-8: Roll forward of combined total capital base over next AA period ($nominal)

Details	2010-11	2011-12	2012-13	2013-14	2014-15
Opening Balance	2,366.9	2,503.8	2,629.5	2,756.2	2,893.8
Add Capex	175.1	173.1	178.0	196.5	218.1
Add Revaluation Of Assets	58.2	61.4	64.5	67.7	71.2
Less Depreciation	89.4	100.2	109.9	120.7	135.8
Less Capital Contributions	4.0	6.4	3.5	3.3	3.2
Less Disposals	3.0	2.3	2.4	2.5	2.7
Add Reused redundant assets	0.0	0.0	0.0	0.0	0.0
Closing Balance	2,503.8	2,629.5	2,756.2	2,893.8	3,041.5

Table 8-9: Roll forward of Wilton to Wollongong capital base over next AA period ($nominal)

Details	2010-11	2011-12	2012-13	2013-14	2014-15
Opening Balance	12.3	12.4	12.5	12.7	12.8
Add Capex	0.1	0.1	0.2	0.2	0.2
Add Revaluation Of Assets	0.3	0.3	0.3	0.3	0.3
Less Depreciation	0.3	0.3	0.3	0.3	0.3
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0
Less Disposals	0.0	0.0	0.0	0.0	0.0
Add Reused redundant assets	0.0	0.0	0.0	0.0	0.0
Closing Balance	12.4	12.5	12.7	12.8	13.0

In its 2005 Final Decision, IPART identified redundant capital on the Wilton to Wollongong pipeline with a value that equated to 20 per cent of the value of the capital base of the pipeline as at 1 July 2005. The Tribunal's finding was based on a significant reduction in utilisation of the pipeline following commissioning of the EGP in 2000-01. The Tribunal required that the redundant capital ($2.13 million in $2005-06) be removed from the value of the capital base for the pipeline from 1, July 2005.[39] Stranding part of the value of the pipeline in this way effectively imposed a capacity constraint by limiting the economic value of the pipeline to the value of then-current usage.

Circumstances have change since the IPART Decision. In particular, with the introduction of the STTM, JGN will not be able to manage capacity utilization on its trunks. The STTM design assumes an unconstrained market hub:

> The aim of the STTM is to create an efficient trading hub. The hub should not have material and enduring pipeline constraints. If there were material and enduring pipeline constraints then this could lead to the need for changes to the STTM design.[40]

Under the STTM, JGN will not have the ability to determine how much and when gas is distributed from the MSP to Wollongong. There is little reason to presume that the Wilton to Wollongong pipeline will continue to be underutilised under the STTM. Moreover, it would be inconsistent with the STTM design assumption of an unconstrained distribution hub to effectively constrain capacity via stranding.

Accordingly the $2.13 million excluded from the capital base from 1 July 2005 is returned to the capital base as re-used redundant assets with effect from 1 July 2010 in accordance with rule 86. The value of this asset is $3.44 million after capitalising the $2.13 million up to 1 July 2010 using JGN's current pre-tax nominal weighted average cost of capital (**WACC**) of 7 per cent and actual / forecast inflation over the period.

Table 8-10: Roll forward of Wilton to Newcastle trunk pipeline capital base over next AA period ($nominal)

Details	2010-11	2011-12	2012-13	2013-14	2014-15
Opening Balance	129.9	133.2	136.0	138.7	141.8
Add Capex	2.9	2.5	2.4	2.8	3.1
Add Revaluation Of Assets	3.1	3.2	3.3	3.3	3.4
Less Depreciation	2.8	2.9	3.0	3.1	3.2
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0
Less Disposals	0.0	0.0	0.0	0.0	0.0
Add Reused redundant assets	0.0	0.0	0.0	0.0	0.0
Closing Balance	133.2	136.0	138.7	141.8	145.2

[39] IPART Final Decision, *Revised Access Arrangement for AGL Gas Networks*, July 2000, , p. 86.

[40] Geoffrey Swier, *Application by Jemena Gas Networks to the National Competition Council for Reclassification of Transmission Assets*, Independent Expert Report, 17 April 2009, p. 3.

Table 8-11: Roll forward of NSW distribution system capital base over next AA period ($nominal)

Details	2010-11	2011-12	2012-13	2013-14	2014-15
Opening Balance	2,224.7	2,358.2	2,481.0	2,604.7	2,739.2
Add Capex	172.1	170.5	175.4	193.5	214.8
Add Revaluation Of Assets	54.8	57.9	60.9	64.1	67.5
Less Depreciation	86.4	97.0	106.6	117.3	132.3
Less Capital Contributions	4.0	6.4	3.5	3.3	3.2
Less Disposals	3.0	2.3	2.4	2.5	2.7
Add Reused redundant assets					
Closing Balance	2,358.2	2,481.0	2,604.7	2,739.2	2,883.4

As stated previously, JGN has deducted forecast depreciation in rolling forward the Capital Base over the current AA period in accordance with IPART's Final Decision.[41] As provided in rule 90(2), JGN elects in its AA to use forecast depreciation, adjusted for the difference between forecast and actual CPI, in rolling forward the capital base to 30 June 2015.

8.6 Capital contributions

In most cases where a user requests a new or changed service, it will be necessary for JGN to expend capital to meet the request. JGN will request a capital contribution from the user where the present value of incremental costs associated with meeting the user's request (including capital and ongoing operating and maintenance costs) exceeds the present value of the incremental revenue that will be generated by the new or changed service. If the user declines to pay the contribution, the work will not proceed.

Capital contributions received by JGN are taxed as income in the year they are received. That tax payment is offset in part by the tax shield arising from depreciation of the user's contribution to the capital cost of the asset over its tax life. The result is that JGN incurs a present value tax cost as a consequence of receiving the contribution. JGN is not compensated for that cost in its regulated revenue.

The capital contributions charged by JGN therefore include an amount, in addition to the user's contribution to the capital cost of the relevant assets, to compensate

[41] IPART Final Decision, *Revised Access Arrangement for AGL Gas Networks*, July 2000, p. 76.

JGN for the present value cost of the tax treatment of the contribution. JGN accounts for this tax cost compensation component of capital contributions as unregulated income. The user's contribution to the capital cost of the asset is excluded from the capital base. It is only JGN's contribution to the cost of the asset, i.e. the total cost of the asset less the user's contribution that enters the capital base. This mechanism prevents JGN from benefiting, through increased revenue, from the user's contribution consistent with rule 82(4). The result is also that JGN's capex is justifiable consistent with rule 79 (2).

Table 8-12: Capital contributions over the current AA period ($nominal)

Details	2005-06	2006-07	2007-08	2008-09	2009-10
Total Contributions Received	7.79	4.98	8.51	6.44	4.04
Less Tax Cost Compensation	0.87	0.26	0.39	0.29	0.46
Contribution to Assets	6.92	4.72	8.12	6.15	3.58
Number of Contributions Received	886	724	772	857	939

Notes: Values for 2008-09 are estimates for the year based on actual data to 30 April, 2009. Values for 2009-10 are forecast. JGN has derived historical values from the capital contributions database that it has maintained in accordance with section 9.2 of its AA.

8.7 Disposals

JGN has assumed that the annual amounts of scrappings/disposals for mains, services, and vehicles will remain constant in real terms at the average of actual amounts for the years 2006 to 2008 inclusive. Scrappings for meters are related to meter replacements, so amounts assumed for this vary from year to year in line with meter replacement expenditure. A batch of regulators will be subject to accelerated replacement in 2009-10 and 2010-11 to maintain their safety at acceptable operating levels. This will result in additional regulator scrappings in those years.

8.8 Capital redundancy policy

JGN proposes a capital redundancy policy in chapter 5 of the AA. The policy is the same as that approved by IPART for the current AA period except that decreased value because of a decrease in utilisation has been removed as a ground for redundancy. This ground is not required by rule 85.

JGN is proposing a capital redundancy mechanism to address uncertainties. It is possible for a capital redundancy mechanism to inadequately address uncertainties if the criteria for redundancy are poorly defined or if an asset can be declared redundant without proper consideration of all the consequences of the declaration. In order to reduce that uncertainty, JGN proposes that the AER should be able to take into account a range of factors when determining whether an asset is redundant. Uncertainty is also reduced by removing decreased value because of a decrease in utilisation as a ground for redundancy

8.9 RIN and rule 72 requirements

Table 8-13 sets out RIN and rule 72 requirements met in chapter 8.

Table 8-13: Summary of RIN responses

RIN/rule 72 reference	RIN requirement	Where addressed in AAI
Capital base at the beginning of the earlier access arrangement period		
RIN 2.3.1.1 Rule 72(1)(a)(i) and 72(1)(b)	(a) Provide in pro forma 1, the opening capital base by asset class at 1 July 2004 and 1 July 2005	Regulatory asset base roll forward model
	(b) Provide in pro forma 1 the capital base approved by the jurisdictional regulator as at 1 July 2004 and 1 July 2005	Regulatory asset base roll forward model Section 8.4
	(c) Provide in pro forma 4 remaining asset lives that reflect the capital base as at 1 July 2005 and the asset lives that reflect the capital base as approved by the jurisdictional regulator as at 30 June 2005	Regulatory asset base roll forward model Sections 8.4 and 10.3
	(d) Provide in the access arrangement proposal submission a reconciliation of the opening capital base in (a) and (b). Include in that reconciliation adjustments for any difference in estimated and actual capex and other adjustments made to the opening capital base as at 1 July 2005 and explain these variations	Section 8.4
Capex in the earlier access arrangement period		
RIN 2.3.1.2	(a) Provide in the access arrangement proposal submission an explanation for: (i) any significant variations between capex approved by the jurisdictional regulator and the actual and/or estimated capex for the earlier access arrangement period (ii) how conforming capex added to the capital base in the earlier access arrangement period meets the code requirements.	Section 4.4 Appendix 7.4: PB review of AMP capex

RIN/rule 72 reference	RIN requirement	Where addressed in AAI
	(b) Provide in pro forma 1 by asset class for each year of the earlier access arrangement period (i) Amounts added to the opening capital base for conforming capex (ii) Amounts for non conforming capex identified as recovered by surcharge, added to a speculative capex investment account (under the code a speculative investment fund), other amounts of non conforming expenditure.	Regulatory asset base roll forward model Sections 4.4 and 8.4
Past capital contributions, speculative investment, reused assets, redundant assets, disposals in the earlier access arrangement period		
RIN 2.3.1.3	Provide in pro forma 1 by asset class for each year of the earlier access arrangement period: (a) Amounts added to the opening capital base for past capital contributions (c) Amounts added to the opening capital base for the reuse of redundant assets (d) Amounts deducted from the opening capital base for redundant assets (e) Amounts deducted from the opening capital base for disposals Note: RIN requirement 2.3.1.3(b) is not relevant because JGN does not have any costs accrued to a speculative capital expenditure account.	Regulatory asset base roll forward model Section 8.6
RIN 2.3.1.3	Provide in the access arrangement proposal submission an explanation for how: (g) Amounts added to the opening capital base for the reuse of redundant assets meet the relevant code criteria Note: RIN requirement 2.3.1.3(f) is not relevant because JGN does not currently have any costs accrued to a speculative capital expenditure account.	Section 8.5
Depreciation in the earlier access arrangement period		
2.3.1.4	Provide in pro forma 4 for each year of the earlier access arrangement period (a) For each asset class amounts deducted from the opening capital base for depreciation including amounts of depreciation for changes to the capital base in earlier access arrangement period. Depreciation for the earlier access arrangement period should account for and distinguish depreciation referable to the opening capital base and amounts added to, or deducted from, the opening capital base for re-used redundant assets, redundant assets, disposals, conforming capex, capital contributions included in the capital base and amounts from the speculative capex account (under the code a speculative investment fund) (b) Asset lives of each asset	Regulatory asset base roll forward model

RIN/rule 72 reference	RIN requirement	Where addressed in AAI
Rate of inflation and adjustment to the capital base in the earlier access arrangement period		
2.3.1.5	(a) Provide in pro forma 3 the rates of inflation used to adjust the capital base for inflation over the earlier access arrangement period (b) Provide in pro forma 1 the adjustments to the capital base for inflation over the earlier access arrangement period	(a) Table 8-3 (b) Regulatory asset base roll forward model
Capital base in the earlier access arrangement period		
2.3.1.6	(a) Provide in pro forma 1 the capital base by asset class for each year of the earlier access arrangement period	(a) Section 8.3 (b) Regulatory asset base roll forward model
Capex that is not conforming the access arrangement period		
2.3.1.8	(g) Provide in the access arrangement proposal submission details of the mechanism to prevent the service provider from benefiting, through increased revenue, from the capital contributions by a user in the access arrangement period referred to in Rule 82(3)	Section 8.6
Capital redundancy policy in the access arrangement period		
2.3.1.9	Provide in the access arrangement proposal submission (a) An outline of the proposed mechanism to remove redundant assets from the capital base including when the mechanism will take effect and if the mechanism includes a proposal for cost sharing between the service provider and users associated with a decline in demand for pipeline services (b) A justification for the mechanism (c) Explain what uncertainty the mechanism may cause and the effect of this uncertainty on the service provider, users and prospective users	Section 8.8 Section 5 of the AA
2.3.11	Provide in pro forma 1 amounts by asset class for each year of the access arrangement period for forecast disposals	Building blocks regulatory model
Rate of inflation and adjustment to the projected capital base in the access arrangement period		
2.3.1.12	(a) Provide in pro forma 1 the adjustment to the capital base to take account of the effects of inflation over the access arrangement period (b) Provide in pro forma 3 the rates of inflation used to adjust the capital base over the access arrangement period	Building blocks regulatory model
Projected capital base in the access arrangement period		
2.3.1.13	Provide in pro forma 1 the capital base by asset class for each year of the access arrangement period	Building blocks regulatory model

9 Cost of Capital

The cost of capital aims to compensate JGN's debt and equity holders for the opportunity cost of lending/investing their funds in the JGN network. The NGR require that this compensation reflect the prevailing market conditions for funding a benchmark efficient gas distribution business with a benchmark capital structure and risk profile.

This chapter sets out the approach adopted by JGN in determining its cost of capital, and the proposed value for cost of capital and is structured as follows:

- *Section 9.1 Summary* – summarises JGN's proposed cost of capital over the current AA period

- *Section 9.2 Law and rules requirements* – describes the rule requirements that JGN's cost of capital must provide for returns that reflect the prevailing market conditions for funding and rely on a well accepted model for forecasting these funding costs

- *Section 9.3 Background* – provides background on IPART's 2005 decision on pre-tax real cost of capital of 7 per cent using a Sharpe-Lintner capital asset pricing model (**CAPM)**

- *Section 9.4 Treatment of tax* – describes JGN's current pre-tax revenue approach to calculate its building blocks revenue and its proposal to do so for the next AA period

- *Section 9.5 Business risk* – provides the basis for JGN's view that gas distribution businesses are more risky than electricity distribution businesses due to higher volume risk. This means that gas businesses have lower credit ratings than electricity businesses

- *Section 9.6 WACC model* – details JGN's proposed approach of using a Fama-French three-factor model to determine its WACC that is fit for purpose

- *Section 9.7 WACC parameters* – sets out JGN's proposed parameters that are consistent with prevailing market conditions and the risks of an efficient gas distributor, as required by rule 87 of the NGR

- *Section 9.8 RIN and rule 72 requirements* – maps the RIN and NGR rule 72 requirements to the relevant sections and chapters.

9.1 Summary

JGN has set its cost of capital using the domestic version of the Fama-French three-factor model **(FF model**) to estimate the cost of equity component of its WACC. JGN proposes a pre-tax nominal WACC of 12.63 per cent.

JGN considers that moving to the FF model to estimate the cost of equity provides an estimate that better reflects the prevailing conditions in the market for funds than the Sharpe-Lintner model as currently applied. Providing a return commensurate with market conditions is critically important to JGN in order for it to be able to fund its required capital program.

JGN's proposed cost of capital reflects the risks of an efficient gas distributor and the prevailing market conditions, in compliance with the NGR. Importantly, JGN considers that gas distributors are inherently more risky businesses than electricity distributors, with higher debt premia. This view has been supported by the AER in previous decisions as well as by other regulators and academics as discussed in section 9.5.

Table 9-1 summarises JGN's proposed WACC parameters as well as resulting WACC variants.

Table 9-1: JGN's proposed WACC Parameters

Parameters	JGN Proposal
Inflation (i)	2.38%
Nominal risk free rate (R_f^n)	5.60%
Real risk free rate	3.15%
Debt margin (D^n)	5.04%
Nominal pre-tax cost of debt	10.64%
Real pre-tax cost of debt	8.08%
Market risk premium (MRP^n)	6.50%
Growth risk premium (HML^n)	6.24%
Size risk premium (SMB^n)	-1.23%
Equity beta (β_e)	Na
Market beta (β_m)	0.59
Growth beta (β_{HML})	0.48
Size beta (β_{SMB})	0.30
Post-tax nominal return on equity	12.06%

Parameters	JGN Proposal
Gearing (D/V)	60%
Dividend imputation (γ)	0.20
Tax rate on equity (T_e)	28.35%
Corporate tax rate (T_c)	30%
Pre-tax real WACC ($WACC^r$)	10.01%
Pre-tax nominal WACC ($WACC^n$)	**12.63%**
Nominal vanilla WACC	11.21%
Real vanilla WACC	8.63%

Notes:

1. Real costs of debt and equity and the risk free rate are calculated from the nominal equivalents using the Fisher equation and forecast inflation.
2. Debt margin is based on an efficient gas business with a BBB credit rating.
3. JGN does not rely on a debt or asset beta to estimate its proposed WACC.

9.2 Rule requirements

JGN must provide the proposed rate of return, the assumptions used to calculate that rate of return and a demonstration of how the rate of return is calculated (rule 72(1)(g)). This return must be:

> commensurate with prevailing conditions in the market for funds and the risk involved in delivering the reference services.[42]

In estimating this return, JGN must assume that the return:

> (i) meets benchmark levels of efficiency; and (ii) uses a financing structure that meets benchmark standards as to gearing and other financial parameters for a going concern and reflects in other respects best practice.[43]

And use:

> a well accepted approach that incorporates the cost of equity and debt, such as the Weighted Average Cost of Capital,...and a well accepted financial model, such as the Capital Asset Pricing Model.[44]

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[42] NGR, rule 87(1).

[43] NGR, rule 87(1).

[44] NGR, rule 87(1).

Further, the governing pricing principles in the NGL require that JGN is "provided with [the] reasonable opportunity to recover at least [its] efficient costs".[45]

9.3 Background

JGN was allowed a pre-tax real cost of capital of 7.0 per cent for its last AA.[46] IPART used the Sharpe-Lintner CAPM to calculate this cost of capital.

For the purpose of the next AA period, JGN has assessed the prevailing market conditions affecting its cost of capital. This has included examination of the relevant requirements of the NGR and well accepted methods for estimating the cost of capital for assets with JGN's risk profile.

9.3.1 Factors affecting JGN's cost of capital

JGN's cost of capital adjusts over time to reflect changes in the financial markets and the performance and position of its business. The key factors affecting JGN's cost of capital are set out below.

Tax

Imputation credits make up part of the return that equity holders get for supplying funds to a firm. Equity holders use these credits to offset against their tax liabilities. The value of these credits varies depending on when they are paid out, whether they are paid out at all and whether equity holders can use them.

Risk

A firm uses its cash flows to compensate equity and debt holders via dividends and interest. These cash flows are inherently risky due to changes in demand and input prices and so the compensation is risky also.

Capital structure

Capital structure refers to the level of debt funding relative to equity funding. The higher the amount of debt funding the higher the risk of bankruptcy as the costs of servicing this debt rises.

Availability of capital

Firms must compete for funding in the market for funds. In the current financial crisis, the supply of funds has fallen while the demand for funds has remained

[45] *National Gas (South Australia) Act 2008*, section 24(2).

[46] IPART Final Decision, *Revised Access Arrangement for AGL Gas Networks*, April 2005, p. 107.

constant. This excess demand has pushed up the cost of attracting funds from debt and equity holders.

These factors are discussed further below.

9.4 Treatment of tax

JGN must provide its proposed method for dealing with taxation and how the tax allowance is calculated to comply with rule 72(1)(h).

In the last three AA reviews, IPART adopted a pre-tax approach to determine JGN's revenue requirement. That is, IPART allowed for taxation by applying a pre-tax rate of return to the value of assets from time to time. The NGR do not stipulate how to make an allowance for tax.

JGN has elected to determine its building block revenue requirement using a pre-tax approach as provided for under rule 72(1)(h)). This means the rate of return used to determine the return on capital is a pre-tax rate of return. As a consequence of this election, it is not necessary to itemise "the estimated cost of corporate income tax for [each] year" as a separate revenue building block consistent with rule 76(c).

Instead, JGN converts its proposed nominal vanilla rate of return to a pre-tax rate of return using an estimated effective tax rate of 28.35 per cent as discussed in section 9.7.8.

Previously, IPART adopted the statutory tax rate of 30 per cent when establishing JGN's pre-tax rate of return. JGN considers this is consistent with the principle of allowing for the costs of a benchmark efficient firm. Notwithstanding this view, JGN has calculated an effective tax rate in line with the AER's draft AA Guideline. To do this, JGN has relied upon the calculation method specified in the AER's published 'Post Tax Revenue Model' for electricity distribution businesses (**PTRM**).[47]

9.5 Business risk

JGN considers that gas networks are riskier than electricity networks because of higher volatility in cash flows from higher volume uncertainty. As a result, an efficient gas network generally has a lower credit rating and higher equity beta (when using the Sharpe-Lintner CAPM) or market beta (when using the FF model) than an efficient electricity network.

[47] AER, *Final Decision on Electricity Distribution Network Service Providers' Post-tax Revenue Model*, 26 June 2008, Appendix B.

Gas volumes are more uncertain than electricity demand because:

- gas networks have more options to expand their networks to enable new, but uncertain demand to connect
- gas is a discretionary fuel, particularly in coastal NSW where the climate is relatively benign
- unlike an electricity network, JGN does not have an exclusive franchise[48] and is therefore subject to ongoing asset bypass risk
- unlike electricity, JGN is subject to a capital redundancy mechanism.

This view is supported by the AER who in its recent review of WACC parameters for electricity distributors and transmitters noted that:

> [It] has previously acknowledged in its explanatory statement that gas businesses may have a higher business risk than electricity businesses due [to] greater volatility in cash-flows from relatively higher volume risk compared to electricity network businesses.[49]

In its draft decision on WACC, the AER presents data that shows that private gas networks tend to have lower credit ratings than private electricity networks.[50] Based on this data, JGN considers that efficient gas networks have credit ratings of BBB or lower (see Table 9.10 of the AER's draft decision). The AER's final decision reinforces this view:

> The AER observes that gas businesses tend to have a lower credit rating (and a higher level of gearing) than electricity businesses….[51]

On this basis, JGN proposes to retain a BBB credit rating for the purpose of assessing its cost of debt.

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[48] JGN's network license is non-exclusive thereby allowing other firms to build competing gas assets within JGN's current network footprint.

[49] AER, *Electricity Transmission and Distribution Network Service Providers Review of the Weighted Average Cost of Capital (WACC) Parameters, Explanatory Statement*, 1 May 2009, p. 108.

[50] AER, *Electricity Transmission and Distribution Network Service Providers Review of the Weighted Average Cost of Capital (WACC) Parameters, Explanatory Statement*, December 2008, Tables 9.4, 9.5, 9.7 and 9.10.

[51] AER, *Electricity Transmission and Distribution Network Service Providers Review of the Weighted Average Cost of Capital (WACC) Parameters*, Explanatory Statement, 1 May 2009, footnote 794, p.348.

9.6 Weighted average cost of capital model

JGN proposes the Officer version of the WACC[52] for which it uses:

- the Fama-French three-factor model to estimate the cost of equity
- observed domestic corporate bond performance to estimate the cost of debt.

9.6.1 WACC proposal

JGN proposes using a nominal pre-tax WACC as defined by Officer[53] as follows:

$$WACC^n = \frac{R_e^n}{1 - T_e(1-\gamma)}\frac{E}{V} + R_d^n \frac{D}{V},$$

where:

- R_e^n is the nominal return on equity
- R_d^n is the nominal return on debt
- $\frac{E}{V}$ is the level of equity
- $\frac{D}{V}$ is the level of gearing
- γ is the level of imputation utilisation
- T_e is the effective tax rate on equity.

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[52] R. R. Officer, 1994, *The cost of capital of a company under an imputation tax system*, Accounting and Finance, vol.34, p.10.

[53] R. R. Officer, 1994, *The cost of capital of a company under an imputation tax system*, Accounting and Finance, vol.34, pp 1–17.

9.6.2 Cost of equity proposal

Summary

Nominal cost of equity is estimated using the FF model as follows:

$$R_e^n = R_f + MRP^n \times \beta_m + SMB^n \times \beta_{SMB} + HML^n \times \beta_{HML} \text{ ,}$$

where:

- R_f^n is the nominal risk free rate
- MRP^n is the nominal market risk premium
- HML^n is the risk premium for high book-to-market firms compared to low book-to-market firms.
- SMB^n is the risk premium for small firms compared to big firms
- β_m is the market beta
- β_{HML} is the beta on the high minus low firm factor
- β_{SMB} is the beta on the small minus big firm factor.

This compares to the Sharpe-Lintner CAPM as follows:

$$R_e^n = R_f + MRP^n \times \beta_e \text{ ,}$$

where β_e is the equity beta.

Model selection

The NGR and NGL allow a distributor to propose a financial model provided that:

- the outcome of the estimation process be as accurate as possible (but not less than) an estimate of the cost of capital associated with the relevant activity (see rule 87(1), rule 74(2)(b) and sections 24(2) and (5) of the NGL)
- the financial model that is used to estimate the rate of return be ‘well accepted’ (rule 87(2)) and any forecast or estimate be ‘arrived at on a reasonable basis’ (rule 74(2)(b)).

There are a number of financial models available to estimate the cost of equity that differ in the factors that are assumed to be priced. The financial model historically employed by the AER for this task has been a version of the Sharpe-Lintner CAPM, i.e.:

$$\mathrm{E}(R_j) = R_f + \beta_j[\mathrm{E}(R_m) - R_f],$$

where

E(R$_j$*)* is the expected return on asset *j*

R_f is the risk-free rate

β_j is asset *j*'s beta, which measures the contribution of the asset to the risk, measured by standard deviation of return, of the market portfolio

R_m is the expected return to the market portfolio of risky assets.

Reasons for adopting the FF model

The CAPM is one of the simplest available financial models and hypothesises that an asset's riskiness is explained by the extent to which it contributes to the risk of the market portfolio. However, since the CAPM's development in the early 1960s a number of more sophisticated pricing models have been developed that either relax the assumptions of the CAPM and/or attempt to reflect the observed behaviour of investors more closely.

One such model that has now gained wide acceptance is the FF model, which seeks to eliminate the errors associated with the way the CAPM prices value and small stocks.[54] More specifically, this model takes account of the fact that the systematic premium that is earned by a stereotypical value or small stock indicates that value and size are characteristics that proxy for risk for which investors require a return.[55] The FF model can be expressed by the following formula:

$$\mathrm{E}(R_j) - R_f = b_j[\mathrm{E}(R_m) - R_f] + h_j HML + s_j SMB,$$

where

b_j, h_j and s_j are the slope coefficients from a multivariate regression of R_j on R_m, *HML* and *SMB*.

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[54] A value stock is one that has a high ratio of the book value of the equity to its market value.

[55] JGN note's that the evidence available in Australia does not permit a conclusion that a premium is earned by small stocks; however, this relationship is clear in the long-term data from the US.

While the AER has traditionally used a version of the Sharpe-Lintner CAPM, the FF model meets all the requirements of the NGR and NGL.

The FF model demonstrably provides an estimate of the required returns that is more accurate than the CAPM. This conclusion is supported by the weight of empirical evidence which suggests that factors other than market beta explain the cross-section of mean returns—namely the book-to-market ratio and market capitalisation of a firm's equity. The FF model explicitly accounts for these factors and as a result leads to a better estimate of the cost of equity than models such as the CAPM. While this relationship was first found in the US, similar results have been found in other major capital markets, namely in Europe, the UK and Japan. A similar relationship has also been found in Australia with evidence supporting the use of book-to-market ratio, although it is less clear that the size factor has been priced in Australia. Furthermore, it has been demonstrated that the FF model substantially reduces the pricing errors associated with the returns to energy utilities compared with the CAPM.

The FF model is a well accepted financial model since:

- it has gained wide acceptance in the academic literature as a reliable predictor of equity returns
- surveys report that a sizable proportion of US managers apply multifactor risk models in investment decision-making, with a significant subset of these managers using size and value factors
- Australian investment portfolios are also more consistent with the predictions of the FF model than with the predictions of the CAPM since investors do not all hold the same portfolio of assets – rather the evidence indicates that different investors hold different portfolios
- the investment strategies of Australian active managers allow investors to tilt their portfolios in a manner consistent with the FF model.

Whilst no regulator is currently using the FF model to set regulated returns, there is a growing acceptance of the FF model. For example, a number of eminent economic experts engaged by the New Zealand Commerce Commission (**the Commission**) identified it as an appropriate model to check the allowed returns on equity for regulated businesses.[56] Subsequently, the Commission updated its draft guideline on the approach to estimating the cost of capital for regulated business,

[56] Julian Franks, Martin Lally and Stewart Myers, *Recommendations to the New Zealand Commerce Commission on an Appropriate Cost of Capital Methodology*, Report to the New Zealand Commerce Commission, 2008, p. 8.

recommending that businesses may use the FF model as a cross-check on the CAPM.[57]

NERA report on the FF model

JGN engaged NERA to compute an estimate of the cost of equity for an Australian gas distributor using the FF model. Their report is provided in Appendix 9.1. This report evaluates the FF model for compliance with the NGR and NGL and estimates the parameters for the FF model for an efficient gas business using current market data. The report also compares the FF model with the Sharpe-Lintner CAPM, including past performance.

JGN relies upon this report to support its proposed WACC and for the parameters of the FF model. Appendix 9.1 provides NERA's full computations, which are summarised below.

FF model parameters

Where appropriate, NERA has populated the FF model with the same data and parameters as those employed by the AER in its recent review of the WACC parameters for electricity lines businesses. Those parameters not shared with the CAPM, have been estimated from data provided by DFA. DFA is an investment group affiliated with Fama and French that explicitly invests along the lines suggested by their research.

Table 9-2 sets out the FF model parameters that JGN relies upon for its proposed cost of equity.

Table 9-2: Domestic Fama-French three-factor model

Parameters	Market	HML	SMB
Risk Premium	6.50%	6.24%	-1.23%
Beta	0.59	0.48	0.30

Note. Estimated using data sampled up to the end of May 2009.

Applying these parameters to a domestic version of the FF model leads to a return on equity that is 6.46 percentage points above the risk-free rate. A risk-free rate of 5.60 per cent was observed over the 20 days up to and including the 31 July 2009, which results in an estimated cost of equity of 12.06 per cent for a gas distributor.[58]

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[57] New Zealand Commerce Commission, *Revised Draft Guidelines: The Commerce Commission's Approach to Estimating the Cost of Capital*, 19 June 2009, p. 21.

[58] In their report, NERA estimate the risk-free rate at 5.11 per cent for the 20 business days to the end of May 2009. Using this rate, NERA estimate the cost of equity as 11.57 per cent.

9.6.3 *Cost of debt proposal*

Nominal cost of debt:

$$R_d^n = R_f^n + D^n ,$$

where:

- R_f^n is the nominal risk free rate
- D^n is the nominal debt margin.

JGN proposes a debt margin of 5.04 per cent. This margin is added to the nominal risk free rate of 5.60 per cent to give JGN's proposed cost of debt of 10.64 per cent.

The AER's Statement of Regulatory Intent on WACC stipulates that the debt margin be determined as follows:

- the observed annualised Australian benchmark corporate bond rate used in the calculation is to relate to corporate bonds with a term to maturity of 10 years
- the debt risk premium over the risk free rate is to be estimated with reference to a bond with a BBB+ credit rating.

JGN notes that a credit rating of BBB reflects the riskiness of gas businesses and is consistent with the AER's WACC decision, see above, which shows that gas businesses typically have this credit rating. Therefore, JGN has determined its debt margin with reference to BBB credit rating.

JGN has determined its debt margin employing the approach submitted by the five Victorian electricity distribution networks for their June 2009 AMI charges applications.[59] This approach relies upon quantitative assessment of the Tabcorp bond as a 5-year fixed rate bond to estimate a debt premium of 4.84 per cent for a BBB+ rated bond with a 10 year term. It also benchmarks favourably against an important alternative source of funds to Australian businesses at the present time, which is to issue corporate bonds in the US and then to purchase the required swaps to convert the US dollar fixed-rate debt into fixed-rate Australian dollar debt.

[59] Citipower, Powercor, United Energy, Jemena and SP AusNet, *Debt risk premium for use in the initial AMI WACC period*, 1 June 2009 provided in Appendix 9.2.

JGN adds a premium of 20 basis points to the AMI debt premium to estimate a debt premium for BBB rated gas businesses of 5.04 per cent. Table 9-3 summarises this calculation.

Table 9-3: Debt premium

	Value
Debt premium from AMI charges application (for BBB rated electricity businesses)	4.84%
Premium between BBB and BBB+ rated bonds	0.20%
Debt premium for gas businesses	5.04%

Notes.

1. Debt premium for the AMI charges application is estimated over the last 10 business days of November 2008 and the first 5 business days of December 2008.
2. Premium between BBB and BBB+ rated bonds is JGN's assessment of the premium from current market data.

JGN recognises that its proposed debt margin will require updating for the final measurement period agreed with the AER. On this basis, JGN submits the method contained in Appendix 9.2 for approval. JGN further submits that, provided the adjustment proposed herein is made to make the debt margin consistent with a BBB corporate bond, its application during the agreed measurement period will result in a cost of debt that is compliant with the NGR.

JGN notes that it is still examining the arguments in support of this position and, if relevant further information becomes available to JGN, it will make that information available to the AER immediately.

9.7 Weighted average cost of capital parameters

Based on the above, JGN calculates a pre tax WACC of 12.63 per cent in accordance with the NGR.

Table 9-4 provides a summary of the parameter values that JGN proposes for its WACC calculation and resulting WACC estimates.

Table 9-4: JGN's proposed WACC parameters for the next AA period

Parameters	Current AA period	Next AA period
Inflation (i)	2.80%	2.38%
Nominal risk free rate (R_f^n)	5.70%	5.60%
Real risk free rate	2.82%	3.15%
Debt margin (D^n)	1.13%–1.22%	5.04%
Normal pre-tax cost of debt	6.83%–6.92%	10.64%
Real pre-tax cost of debt	3.92%–4.01%	8.08%
Market risk premium (MRP^n)	5.5%–6.5%	6.50%
Growth risk premium (HML^n)	Na	6.24%
Size risk premium (SMB^n)	Na	-1.23%
Equity beta (β_e)	0.8–1.0	Na
Market beta (β_m)	Na	0.59
Growth beta (β_{HML})	Na	0.48
Size beta (β_{SMB})	Na	0.30
Post-tax nominal return on equity	10.10%–12.20%	12.06%
Gearing (D/V)	60%	60%
Dividend imputation (γ)	0.5–0.3	0.20
Tax rate on equity (T_e)	30.00%	28.35%
Corporate tax rate	30%	30%
Pre-tax real WACC ($WACC^r$)	5.9–7.3%	10.01%
Selected Pre-tax WACC ($WACC^r$)	7.00%	10.01%
Pre-tax nominal WACC ($WACC^n$)	**10.00%**	**12.63%**
Nominal vanilla WACC	8.14%–9.03%	11.21%
Real vanilla WACC	5.19%–6.06%	8.63%

Source: Current AA period parameters from Table 8.6 of IPART (2005). [60]

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[60] IPART, *Final Decision*, *Revised Access Arrangement for AGL Gas Networks*, April 2005, p. 104.

JGN estimates these parameters in accordance with rule 87 and the Draft AA Guidelines.

9.7.1 Inflation

JGN proposes an inflation forecast of 2.38 per cent. Here, forecast inflation is the geometric average of the forecast annual inflation for each of the ten years from 2010 to 2019 as follows:

Table 9-5: Forecast Inflation

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Inflation Forecast	2.50%	1.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Geometric Average										**2.38%**

Note: Inflation forecasts are for the year to June.

Source: Reserve Bank of Australia, *Statement on Monetary Policy*, 8 May 2009, page 69.

The ten annual inflation forecasts:

- for the first two years, are the expected inflation outcomes stated in the Reserve Bank of Australia's (RBA's) most recent Statement on Monetary Policy
- for the subsequent eight years, are the midpoint of the RBA's long term inflation target range. The range is 2 per cent to 3 per cent, so the midpoint is 2.50 per cent.

This approach is consistent with the AER's approach in the recent price determinations for NSW and ACT electricity distributors.

9.7.2 Gearing

JGN proposes a gearing ratio of 60 per cent, consistent with the assumed efficient level of debt chosen by the AER in its final WACC decision and in the current IPART decision.

This ratio is considered efficient for a stand-alone gas distribution business. It is consistent with the proposed figure for the cost of equity and the allowance for debt margin.

9.7.3 Nominal risk free rate

The nominal risk free rate is 5.60 per cent, based on the 20-day historical average of the annualised yield on 10 year Commonwealth Government Securities (**CGS**) to 31 July 2009 using the indicative mid rates published by the RBA.

JGN estimates the yield on a 10 year CGS maturing at the 20 business days to 31 July 2019 by interpolating on a straight-line basis the yields on the CGS bonds maturing at 15 March 2019 and 15 April 2020.

9.7.4 Market risk premium

JGN proposes a market risk premium (**MRP**) of 6.5 per cent, based on the AER's final WACC decision. This estimate reflects the minimum premium that an efficient gas business needs to compensate for the non-diversifiable risk that is influenced by the current financial and economic crises.

Historical based estimates of the MRP, particularly those spanning long time periods, are the most appropriate and relevant proxy for the forward–looking equity risk premium that is taken into account in the CAPM.

9.7.5 Fama-French factors and betas

JGN relies upon NERA's report for the parameters of the FF model. Appendix 9.1 provides NERA's full computations, which are summarised in Table 9-2 above.

9.7.6 Debt margin

JGN proposes a debt margin of 5.04 per cent. This margin is added to the nominal risk free rate of 5.60 per cent to give JGN's proposed cost of debt of 10.64 per cent as set out in section 9.6.3.

9.7.7 Dividend imputation

JGN proposes a value of imputation credits (or gamma) of 0.2.

Gamma is the subject of much debate between regulators and regulated businesses. It is JGN's strongly held view that the best and most credible evidence and analysis supports a value for gamma of zero.

Gamma is the market value of the imputation credits that are created by a firm, and is the product of the assumed proportion of the credits created that are distributed to investors (the payout ratio **F**) and the market value of imputation credits once in the hands of investors (**theta**). In its final decision on WACC, the AER adopts an assumed payout ratio of one. This assumption is discussed further below.

JGN considers that dividend drop-off studies are the most reliable and accurate method for estimating theta, but recognises that the AER also relies on tax statistics to estimate a value of 0.65 in the recent WACC decision for electricity businesses.

Dividend drop-off studies

SFG Consulting (**SFG**) recently quantified the value of theta between 0.2 and 0.35 using a dividend drop-off study.[61] Even if a payout ratio of one is assumed (see below), these results suggest a gamma of less than 0.5.

JGN considers that the SFG study is more comprehensive than the 2006 Beggs and Skeel study[62] that the AER relies on in its final decision on WACC[63] because the SFG results are based on:

- a much larger cross section of firms
- a longer and more recent data period.

Moreover, after correcting for perceived deficiencies in the SFG study, the AER found that the study suggests a theta of between -0.23 and 0.47.[64] Again assuming a payout ratio of one, these results suggest a gamma of less than 0.5 and certainly less than 0.65.

Tax statistics

JGN considers that taxation statistics do not provide an accurate estimate of the value of imputation credits. These statistics measure the quantum of corporate taxation, the amount of credits distributed and the amount of credits claimed.

But the amount of credits claimed is not the value of those credits. Shareholders bear risk when earning the dividends and imputation credits, and must wait before they are distributed. Necessarily, shareholders discount that value of these credits for risk and the time value of money—a process that tax statistics do not capture.

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[61] SFG Consulting, *Market practice in relation to franking credits and WACC: Response to AER proposed revision of WACC parameters*, Report prepared for ENA, APIA, and Grid Australia, 1 February 2009.

[62] D. Beggs and C. L. Skeels, *Market arbitrage of cash dividends and franking credits,* The Economic Record, volume 82, number 258, September 2006, p. 247.

[63] AER, *Electricity Transmission and Distribution Network Service Providers Review of the Weighted Average Cost of Capital (WACC) Parameters, Explanatory Statement*,1 May 2009, p. 400 footnote 794.

[64] AER, *Electricity Transmission and Distribution Network Service Providers Review of the Weighted Average Cost of Capital (WACC) Parameters, Explanatory Statement*, 1 May 2009, p. 400, footnote 794 and p. 441 footnote 1081.

Synergies Economic Consulting (**Synergies**) has undertaken new research using tax statistics from the ATO covering the period 2003 to 2007. This study observed that the payout ratio over this period was between 58 per cent and 77 per cent—with an average of 66 per cent. This average is largely consistent with the findings of Hathaway and Officer that estimates the payout ratio at 0.71,[65] but is significantly different from the payout ratio of 1 assumed by the AER in the electricity WACC decision.

JGN considers that the best estimate of the payout ratio is 0.66 based on the Synergies study because it uses observable market data.

The Synergies study also estimates that investors only utilise 35 per cent on average of the credits that they receive, which means that the maximum possible value for theta is 0.35 if a payout ratio of 1 is assumed, or 0.23 if the average observed payout ratio of 0.66 is assumed instead.[66] Synergies highlight that the lowest feasible value for gamma is zero, which is consistent with JGN's view that the most appropriate value for gamma is also zero.

JGN considers that the Synergies study sets an upper bound for gamma of 0.23 based on a payout ratio of 0.66.[67] This upper bound is consistent with the findings of the SFG study, which estimates a gamma range of between 0.13 and 0.23 if a payout ratio of 0.66 is used.

Proposal

For the purpose of this submission, JGN proposes a gamma range of 0 to 0.23, relying on the Synergies study to set the upper end of this range and the theoretical argument that gamma is zero to set the lower end. JGN proposes a gamma of 0.2 from this range.

To be clear, JGN considers that the AER's conclusions in the electricity WACC decision about the value of imputation credits in the hands of investors and the payout ratio are incorrect and do not meet the requirements of the NGR.

9.7.8 Tax rate on equity

JGN calculates an effective tax rate on equity of 28.35 per cent using the method contained in the AER's PTRM.

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65 N. Hathaway and B. Officer, *The Value of Imputation Tax Credits – Update 2004*, Capital Research Pty Ltd, November 2004, pp.13 and 24.

66 Synergies Economic Consulting, *Gamma: New Analysis Using Tax Statistics*, 28 May 2009, p. 6.

67 Synergies Economic Consulting, *Gamma: New Analysis Using Tax Statistics*, 28 May 2009, p. 8.

Under the IPART approach, JGN did not need to calculate an effective tax rate. So, for the next AA period, JGN proposes using the calculation method adopted by the AER in its post-tax revenue model. This method is summarised in Appendix 9.3.

9.8 RIN and rule 72 requirements

Table 9-6 sets out RIN and rule 72 requirements met in chapter 9.

Table 9-6: Summary of RIN responses

RIN/rule 72 reference	RIN requirement	Where addressed in AAI
WACC		
RIN 2.3.1.14	**Weighted average cost of capital and CAPM**	
	(a) Provide in pro forma 2 the values of parameters that comprise the weighted average cost of capital (WACC) methodology and CAPM methodology	(a) Table 9-1 and Table 9-4
	(b) Provide in the access arrangement proposal submission a justification for the value for each of the parameters used in the WACC derivation	(b) Not applicable as alternative methodology used
	(c) Provide in the access arrangement proposal submission an explanation about how the proposed rate of return complies with rule 87.	(c) Not applicable as alternative methodology used
RIN 2.3.1.14 Rule 72(1)(g)	**Method other than weighted average cost of capital** Provide in the access arrangement proposal submission	
	(d) An outline of the proposed methodology for the rate of return	(d) Section 9.6
	(e) A quantification of the rate of return using this methodology including any justification for the use of parameters in this methodology	(e) Section 9.7
	(f) An explanation about how the proposed rate of return complies with rule 87	(f) Section 9.6. Appendix 9.1: NERA report on Fama French cost of equity model
RIN 2.3.1.14 Rule 72(1)(h)	**Rate of return and taxation method** Provide in the access arrangement proposal submission	
	(g) Details of the proposed method for dealing with taxation and a demonstration of how tax allowance is calculated	Section 9.4
	(h) Where a pre-tax rate of return is proposed provide an explanation of how the proposed tax rate complies with rule 74(2)(a)	Section 9.7.8

RIN/rule 72 reference	RIN requirement	Where addressed in AAI
Estimated cost of corporate income tax		
RIN 2.3.3	If applicable (a) Provide in pro forma 5 i. an estimate of the cost of corporate income tax over the access arrangement period (b) Provide in the access arrangement proposal submission details of how the estimated cost of corporate tax was calculated (c) Refer also to section 2.4 of this notice for further information requirements in relation to the treatment of taxation.	Not applicable. As stated in section 9.4, JGN has elected to determine its building block revenue requirement using a pre-tax approach as provided for under rule 72(1)(h). This means the rate of return used to determine the return on capital is a pre-tax rate of return.
Tax asset base		
2.4	Regardless of the methodology adopted for taxation provide in pro forma 5 the following information forecast as at 1 July 2010 (a) Tax standard life for each asset class (b) Remaining tax life for each asset class (c) Tax asset base or remaining tax asset value for each asset class (d) An estimate of the carry forward tax loss	Building blocks regulatory model Appendix 9.3: JGN effective tax rate

10 Depreciation

Depreciation is the means by which JGN recovers its capital investment. This chapter sets out JGN's proposed depreciation schedule.

This chapter is structured as follows:

- *Section 10.1 Summary* – summarises JGN's depreciation approach
- *Section 10.2 Law and rules requirements* – describes the rule requirements for JGN's depreciation schedule to reflect the economic life of the assets, recover costs of assets only once and have regard to the business' cash flow requirements
- *Section 10.3 Assumptions on economic life of assets for regulatory depreciation* – explains that JGN proposes to retain its existing asset lives
- *Section 10.4 Depreciation and accumulated depreciation* – sets out JGN's depreciation schedule based on the regulatory asset lives
- *Section 10.5 RIN and rule 72 requirements* – maps the RIN and NGR rule 72 requirements to the relevant sections, chapters and regulatory models.

10.1 Summary

JGN has established a depreciation schedule that reflects the economic lives and cash flow needs of the business consistent with the NGR requirements.

Table 10-1 summaries JGN's forecast deprecation over the next AA period by applying the real straight-line depreciation method.

Table 10-1: Forecast depreciation over next AA period ($nominal)

Deprecation	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Total	89.42	100.19	109.91	120.69	135.75	555.96

10.2 Law and rules requirements

Rule 89(1)(e) states that JGN's depreciation schedule should be designed to allow for its reasonable needs for cash-flow to meet financing, non-capital and other costs. Therefore, JGN notes that if the AER rejects aspects of JGN's proposed access arrangement in its draft determination, JGN may propose different asset lives to match its cash flow and financing requirements.

Rule 89 of the NGR sets out the depreciation criteria.

> (1) The depreciation schedule should be designed:
>
> (a) so that reference tariffs will vary, over time, in a way that promotes efficient growth in the market for reference services
>
> (b) so that each asset or group of assets is depreciated over the economic life of that asset or group of assets
>
> (c) so as to allow, as far as reasonably practicable, for adjustment reflecting changes in the expected economic life of a particular asset, or a particular group of assets
>
> (d) so that (subject to the rules about capital redundancy), an asset is depreciated only once (i.e. that the amount by which the asset is depreciated over its economic life does not exceed the value of the asset at the time of its inclusion in the capital base (adjusted, if the accounting method approved by the AER permits, for inflation))
>
> (e) so as to allow for the service provider's reasonable needs for cash flow to meet financing, non-capital and other costs.

10.3 Assumptions on economic life of assets for regulatory depreciation

JGN proposes to determine the annual amount of regulatory depreciation for each asset class by applying the real straight-line depreciation method to the opening regulatory value of each asset class for each financial year. Real straight-line depreciation (as distinct from historic cost straight line) involves deducting the same real amount of depreciation in each year of an asset's life. This is consistent with JGN's election to account for inflation by indexing the capital base.[68]

The real straight-line depreciation profile produces a cost recovery path for new assets that is better aligned to expected market growth than alternatives such as historic cost straight-line or declining balance (rule 89(1)(a)). The profile does not "involve deferral of a substantial proportion of depreciation" as contemplated by rule 89(2).

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[68] This also accords with the methodology contained in the AER's published post tax revenue model (PTRM).

The following economic lives have been used for regulatory purposes.

Table 10-2: Economic lives of JGN assets

Asset Class	Economic Asset Life (Years)
System Assets	
Trunk Wilton-Sydney	80
Trunk Sydney-Newcastle	80
Trunk Wilton-Wollongong	80
Contract Meters	20
Fixed Plant - Distribution	50
HP Mains	80
HP Services	50
MP Mains	50
MP Services	50
Meter Reading Devices	20
Country POTS	50
Tariff Meters	20
Building	48
Computers	5
Software	5
Fixed Plant	10
Furniture	10
Land	0
Leasehold Improvements	10
Low value assets	10
Mobile Plant	10
Vehicles	4
All assets	53

These economic lives are the same as those used in the 2006-10 AA and are consistent with the design lives used by JGN in engineering evaluations. Maintaining the economic lives used previously also avoids revenue volatility between AA periods (rules 89(1)(b)). JGN does not consider it necessary or practicable to adjust the economic lives adopted for regulatory purposes in this proposal (rule 89(1)(c)).

The real straight line depreciation schedule will result in the value of each asset (with adjustment for inflation through indexation of the capital base) being recovered once over the asset's economic life (rule 89(1)(d)). The cash flows that result when depreciation is determined in this way are also consistent with JGN's reasonable needs to meet financing, non-capital and other costs, while maintaining a benchmark credit rating of BBB (refer section 9.7.6) (rules 89(1)(e)).

JGN makes this proposal on the basis of the cash-flow achieved through its proposed price path set out in section 13.8. This price path has been established having regard to JGN's cash flow requirements necessary to deliver its proposed capital program.

10.4 Depreciation and accumulated depreciation

Depreciation for each year of the current AA period is shown in aggregate in chapter 8.

Accumulated regulatory depreciation for the capital base at 30 June 2010 is set out in Table 10-3.

Table 10-3: Regulatory depreciation as at 30 June 2010

	Escalated Gross Regulatory Value	Accumulated Depreciation	Remaining Asset Life
Trunk pipeline (Wilton-Newcastle)	213.75	-83.85	48.10
Trunk pipeline (Wilton-Wollongong)	16.48	-7.67	42.82
Distribution system:			
Country POTS	10.95	-3.38	35.36
Contract meters	11.59	-7.03	9.23
Tariff meters	327.00	-156.72	10.60
Meter reading devices	17.93	-0.59	19.30
Fixed plant	75.22	-19.31	37.47
HP mains	475.16	-126.71	58.74
MP mains	1,802.19	-763.57	28.98
HP services	5.06	-2.38	26.35
MP services	777.63	-218.19	36.00
Total system assets	**3,732.97**	**-1,389.40**	
Non-system assets	**103.83**	**-84.15**	
Total regulatory asset base	**3,836.80**	**-1,473.55**	

Notes: Values based on:

1. actual capex and disposals to June 2008 and forecasts for 2008-09 and 2009-10
2. depreciation for the period to June 2010 as set out in IPART's 2005 Final Decision adjusted for actual inflation over the period
3. forecast depreciation for the year ended June 2005.

Forecast regulatory depreciation for the next AA period, calculated using the methodology set out above, is provided in Table 10-4.

Table 10-4: Forecast depreciation over next AA period ($nominal)

Asset category	2010-11	2011-12	2012-13	2013-14	2014-15	Total
Wilton/Wollongong	0.29	0.30	0.31	0.32	0.33	1.56
Wilton/ Newcastle	2.75	2.85	2.95	3.06	3.17	14.78
Distribution network	86.38	97.03	106.65	117.31	132.25	539.62
Total	**89.42**	**100.19**	**109.91**	**120.69**	**135.75**	**555.96**

JGN intends to use forecast depreciation for the next AA period (adjusted for the difference between forecast and actual CPI) in rolling forward the asset base to the beginning of the next AA period beginning on 1 July 2015 (rule 90(2)).

10.5 RIN and rule 72 requirements

Table 10-5 sets out RIN and rule 72 requirements met in chapter 10.

Table 10-5: Summary of RIN responses

RIN/rule 72 reference	RIN requirement	Where addressed in AAI
Depreciation		
RIN 2.3.2(a) Rule 72(1)(c)(ii)	Provide in pro forma 4 (i) amounts for forecast depreciation disaggregated for components by asset class for each year of the access arrangement period. The forecast depreciation should account for and identify depreciation referable to the opening capital base forecast conforming expenditure, other capex, forecast disposals and other amounts that may be added or deducted to the projected capital based under the Rules (ii) details of the asset lives for each asset	(i) Regulatory asset base roll forward model and building blocks regulatory model. (ii)Table 10-2
RIN 2.3.2(b)	Provide in the access arrangement proposal submission an outline of: (ii) how the depreciation schedule varies over time in a way that promotes efficient growth in the market for reference services (iii) how each asset group of assets is depreciated over the economic life of that group of assets (iv) if applicable, what adjustments have been made to reflect changes in the expected economic life of a particular	(ii) Section 10.3 (iii) Section 10.4 (iv) Not applicable, but note section 10.1

RIN/rule 72 reference	RIN requirement	Where addressed in AAI
	asset or group of assets	
	(v) how each asset is depreciated only once	(v) Section 10.3
	(vi) how the depreciation schedule allows for the service provider's reasonable needs for cash flow to meet financing, non capital and other costs	(vi) Section 10.1, 10.2 and 10.3
	(vii) how the depreciation schedules comply with the requirements in Rule 89(2)	(vii) Section 10.3

11 Incentive mechanisms

The NGR allow networks and the AER to propose incentive arrangements that motivate particular behaviours considered to support the NGO.

This chapter sets out JGN's proposed incentive arrangements.

This chapter is structured as follows:

- *Section 11.1 Summary* – summarises JGN proposed incentive mechanism
- *Section 11.2 Law and rules requirements* – identifies that the NGR allow JGN to propose incentive mechanisms
- *Section 11.3 Existing incentive mechanisms* – sets out incentive mechanisms contained in JGN's current AA
- *Section 11.4 Proposed incentive mechanisms* – details JGN's proposed incentive mechanism.
- *Section 11.5 RIN and rule 72 requirements* – maps the RIN and NGR rule 72 requirements to the relevant sections and chapters.

11.1 Summary

JGN proposes to retain the effect of current UAG and price cap mechanisms but treat them as elements of the annual tariff variation mechanism in its AA. JGN considers that this treatment is more in keeping with the intent of the relevant incentive mechanism and tariff variation rules and that it improves consistency with how these mechanisms are treated in other network's AAs.

JGN proposes one incentive mechanism for the next AA period—a market expansion mechanism (**MEM**)—that gives JGN the incentive to expand the network to unreticulated suburbs and towns in the Sydney region in addition to business as usual short mains extensions which have been included in the JGN capex forecast.

11.2 Law and rules requirements

The NGR rule 98 allows JGN to propose incentive mechanisms to 'encourage efficiency in the provision of services'. Incentive mechanisms give financial penalties or rewards to motivate particular service provider behaviour. These mechanisms must be consistent with the revenue and pricing principles set out in the NGL.

In proposing an incentive mechanism JGN has had regard to the following revenue and pricing principles that are contained at section 24 of the NGL:

> (3) A service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides. The economic efficiency that should be promoted includes:
>
> 1. efficient investment in, or in connection with, a pipeline with which the service provider provides reference services; and
> 2. the efficient provision of pipeline services; and
> 3. the efficient use of the pipeline
>
> (5) A reference tariff should allow for a return commensurate with the regulatory and commercial risks involved in providing the reference service to which that tariff relates
>
> (6) Regard should be had to the economic costs and risks of the potential for under and over investment by a service provider in a pipeline with which the service provider provides pipeline services

JGN has also had regard to the NGO provided at section 23 of the NGL:

> The national gas objective is to promote efficient investment in, and efficient use of, natural gas services for the long term interest of consumers of natural gas with respect to price, quality, reliability and security of supply of natural gas.

11.3 Existing incentive mechanisms

JGN's current AA[69] identifies two incentive mechanisms:

- *unaccounted for gas* – JGN receives compensation for UAG up to a target rate of 2.1 per cent. JGN benefits by keeping this compensation where it achieves UAG less than 2.1 per cent but bears additional unfunded costs where UAG is greater than 2.1 per cent. Over the past three years, JGN's UAG forecasts as reported to IPART have averaged 2.4 per cent, resulting in JGN sustaining financial losses
- *price cap* – JGN's approved tariffs apply throughout the current AA period regardless of whether the forecasts on which the tariffs were determined are

[69] AGL Gas Networks, *Access Arrangement for NSW Network*, June 2005.

realised. JGN benefits from: 1) additional revenue if demand exceeds forecast; or 2) higher profits if costs are less than forecast. JGN also bears losses if: 1) demand is less than forecast; or 2) costs are greater than forecast. In the current period, JGN's demand was less than IPART had approved. JGN has consequently foregone approximately [5] per cent of its revenues over the three years to June 2008 relative to the cost of service determined by IPART.

JGN proposes to retain the effect of these mechanisms which the current AA identifies as incentive mechanisms. However, JGN is of the view that under the new NGR, these mechanisms are better characterised as elements of the annual tariff variation mechanism as set out in section 15.4.1. JGN considers that this treatment is more in keeping with the intent of the relevant incentive mechanism and tariff variation rules and that it improves consistency with how these mechanisms are treated in other network's AAs.

11.4 Proposed incentive mechanisms

JGN proposes an incentive mechanism for the next AA period, the MEM, which motivates JGN to expand the network to unreticulated suburbs and towns in the Sydney region in addition to business as usual short mains extensions which have been included in JGN's capex forecast.

11.4.1 Market expansion mechanism

JGN's proposed AA includes provision for an incentive mechanism to motivate JGN to expand its network into unreticulated suburbs and towns.

JGN can achieve significant cost efficiencies from large-scale expansion projects, but cannot always achieve rates of return sufficient to secure the limited discretionary capital available when competing with other unregulated investments. This is notwithstanding that these rates of return generally satisfy the regulatory hurdle of the regulated WACC return.

If JGN includes targeted expansion projects in its AA forecasts, the costs and demand are both included in the price reset and netted out at the regulated WACC thereby not addressing the incentive problem. In the current financial climate, JGN believes that higher-powered investment incentives are required to attract the necessary capital.

The NGR, and JGN's existing AA, currently allow JGN to invest in speculative capital, which the regulator will then assess for rule compliance at the next review and roll into the RAB with accrued financing costs. JGN proposes a modification to this mechanism to provide additional expansion investment incentives.

JGN proposes that investment in expanding the network into previously established unreticulated areas by way of specific large annual scale projects be allocated to the speculative investment fund with an adjustment. The investment, including capitalised marketing costs directly associated with the investment, and associated demand would not be rolled into the RAB and pricing reset until five years after the commencement of the specific reticulation project. This would allow JGN to retain the additional benefit of five years worth of incremental revenues and provide a stronger incentive for JGN to achieve more rapid growth in customers and gas consumption.

After five years, the capex and demand would be rolled into the RAB and regulated prices. JGN anticipates that the reduced reticulation costs and expected connection rates mean that when the incremental costs and incremental forecast volumes associated with the expansion projects are rolled into the regulatory prices after year five, they will result in a lower average price for existing customers.

By providing an incentive to expand the network to more customers than would otherwise be commercially attractive, and contributing to a lower average price to all customers in the long term, JGN considers that this incentive mechanism is consistent with the gas market objective and with the pricing principles set out in NGL ss. 24(3), (5) and (6).

11.5 RIN and rule 72 requirements

Table 11-1 sets out RIN and rule 72 requirements met in chapter 11.

Table 11-1: Summary of RIN responses

RIN/rule 72 reference	RIN requirement	Where addressed in AAI
Incentive Mechanisms		
RIN 2.3.4.2 Rule 72(1)(l)	Provide for each incentive mechanism in the access arrangement proposal submission (a) An outline of the incentive mechanism and its operation in the access arrangement period (b) An explanation of the rationale for any proposed incentive mechanisms including how the incentive mechanism is intended to encourage efficiency of the provision of services and is consistent with the revenue and pricing principles, with reference to those principles (c) Any relevant analyses or reports that support the proposed incentive mechanism	(a) Section 11.4 (b) Section 11.4 (c) N/A

12 Revenue requirement

JGN has determined its total revenue requirement using the building block approach (in accordance with section 76 of the NGR).

The building block components are:

- a return on the projected capital base described in chapters 8 and 9
- depreciation of the projected capital base set out in chapter 10
- a forecast of opex detailed in chapter 6.

This chapter sets out JGN's total revenue requirement.

12.1 Summary

JGN's total required revenues for each year of the next AA period are set out in the following table.

Table 12-1: JGN revenue requirement

Building block	2010-11	2011-12	2012-13	2013-14	2014-15
Return on capital	302.18	311.44	319.45	327.66	336.71
Return of capital (depreciation)	30.50	37.00	42.34	48.23	57.37
Opex	134.13	138.43	149.16	153.98	159.43
Revenue requirement	**466.81**	**486.87**	**510.95**	**529.86**	**553.51**

Having determined the total costs of JGN's service and revenue requirements, JGN has allocated these costs and revenues between pipeline services, and between customers. Section 13.7 outlines the cost allocation methodology.

JGN has then specified price paths for its reference services to smooth its required revenue for the haulage reference service and achieve price stability over the AA period. This smoothing gives rise to the price paths (P0 and X factors) set out in section 13.8.

12.2 RIN and rule 72 requirements

Table 12-2 sets out RIN and rule 72 requirements met in chapter 12.

Table 12-2: Summary of RIN responses

RIN/rule 72 reference	RIN requirement	Where addressed in AAI
Revenue Requirement		
RIN 2.3.6 Rule 72(1)(m)	Provide in pro forma 7 a summary of total revenue each year of the access arrangement period which includes each of the relevant building block components for the access arrangement period	Section 12.1

Part 3 – Access Arrangement Pricing

13 Services

JGN's AA includes both reference and non-reference services.

A reference service is a pipeline service with standard terms and conditions approved by the AER under the NGR. JGN's AA is the means by which it specifies the reference services it offers to customers of its four covered pipelines.

A non-reference service is a service provided on specific terms not governed by JGN's AA. These are negotiated on a case by case basis or specified in a schedule of services that are ancillary to JGN's reference services.

This chapter sets out the reference services JGN proposes to provide in its AA and how and why these differ to those in the current AA. It also sets out JGN's non-reference services.

This chapter is structured as follows:

- *Section 13.1 Summary* – summarises JGN's proposed reference services
- *Section 13.2 Rule requirements* – identifies that JGN must specify its pipeline reference services, justify any service bundling and allocate a share of required revenues to each reference service
- *Section 13.3 Background* – discusses JGN's relatively complex current reference service offerings
- *Section 13.4 Proposed reference services* – shows that JGN has simplified its proposed reference services into two services
- *Section 13.5 Proposed non-reference services and ancillary fees*– describes the four different ancillary services offered by JGN
- *Section 13.6 Reasons for changes in reference services* – explains how establishment of the STTM and permanent reclassification of JGN's trunk pipelines have enabled JGN to significantly simply its reference services
- *Section 13.7 Cost allocation to services* - demonstrates that JGN has allocated its direct and indirect costs to its reference services in accordance with the NGR
- *Section 13.8 Price path* – sets out the price path JGN proposes to recover its cost of service for haulage reference services

- *Section 13.9 RIN and rule 72 requirements* – maps the RIN and NGR rule 72 requirements to the relevant sections, chapters and regulatory models.

13.1 Summary

JGN's proposed reference services in for its revised AA are:

- *haulage service* - a service for transportation of gas by JGN through its network to a single eligible delivery point for the use of a single customer

- *meter data service* - a service for the provision of meter reading and on-site data and communication equipment to a delivery point.

13.2 Rule requirements

A reference service is defined in rule 101(2) of the NGR to be a pipeline service that is likely to be sought by a significant part of the market. The NGR include the following requirements for reference services:

- the AA/AAI must include a description of the pipeline services the service provider proposes to provide by means of the pipeline under rule 48(1)(b)

- the AA/AAI must specify the reference services under rules 48(1)(c) and 101(1)

- bundling of services is prohibited unless reasonably necessary under rule 109.

Rule 93 also includes the following requirements for allocation of costs to reference services:

- Total revenue is to be allocated between reference and other services in the ratio in which costs are allocated between reference and other services.

- Costs are to be allocated between reference and other services as follows:

  – costs directly attributable to reference services are to be allocated to those services

  – costs directly attributable to pipeline services that are not reference services are to be allocated to those services

  – other costs are to be allocated between reference and other services on a basis (which must be consistent with the revenue and pricing principles) determined or approved by the AER.

- The AER may, however, permit the allocation of the costs of rebateable services, in whole or part, to reference services if:
  - the AER is satisfied that the service provider will apply an appropriate portion of the revenue generated from the sale of rebateable services to provide price rebates (or refunds) to the users of reference services
  - any other conditions determined by the AER are satisfied.

13.3 Background

JGN's current AA includes seven separate reference services. This is a reflection of the following factors:

- JGN's historic market segmentation was through reference service specification rather than through specification of tariff classes within a given reference service
- JGN provided separately-identified reference services from its trunk pipelines and local network.

Trunk pipelines were subject to a derogation from transmission classification that had a finite term. JGN needed to structure its reference services in anticipation of the derogation expiring.

JGN considers there are significant administrative benefits available through simplifying its reference service offerings. Moreover, the NCC has approved a permanent reclassification of JGN's trunk pipelines as distribution pipelines.[70] Given these factors, JGN has significantly simplified its reference service offerings. JGN now proposes only two reference services.

13.4 Proposed reference services

JGN's 2010-11 to 2014-15 AA provides for two types of reference services to users. This section specifies JGN's proposed reference services as required by rule 101(1), and describes:

- why bundling of the two services is necessary for compliance with rule 109

[70] National Competition Council, *National Gas Law: Application by Jemena Gas Networks (NSW) Limited for reclassification of the Northern Trunk and Southern Trunk pipelines - Final Decision and Statement of Reasons*, 29 June 2009.

- how the services are required by a significant part of the market for compliance with rule 101(2).

It is important to note that bundling the two non-gratuitous services does not preclude unbundled provision. Any user can negotiate for any service, with recourse to binding dispute resolution if agreement cannot be reached. Further, and consistent with JGN's current AA terms, JGN's proposed AA has specific provision that if meter data services become contestable in NSW during the AA, these would cease to be a reference service.

13.4.1 Haulage service

Nature of the service

The haulage service is for transportation of gas by JGN through its network to a single eligible delivery point for the use of a single customer.

Bundling

JGN provides this service in conjunction with the meter data service. This is reasonably necessary and currently provided as a non-gratuitous bundled service because the meter reading and data processing is required to enable billing for the haulage service. On this basis, JGN considers this bundling complies with rule 109 of the NGR.

Required by a significant part of the market

JGN is a provider of gas transportation services from gas receipt points into its network to delivery points at customers' premises. As the primary function of its network, haulage reference services are required by the entire JGN customer base.

13.4.2 Meter data service

Nature of the service

The meter data service is a service for the provision of meter reading and on-site data and communication equipment to a delivery point.

Bundling

JGN provides this service in conjunction with the haulage service. This is reasonably necessary and currently provided as a non-gratuitous bundled service because the meter reading and data processing is required to enable billing for the haulage service. On this basis, JGN considers this bundling complies with rule 109.

Required by a significant part of the market

JGN is a provider of gas transportation services from gas receipt points into its network to delivery points at customers' premises. A meter data service is required by all users to measure the amount of gas taken by a delivery point for market balancing and billing functions. Consequently, this service is required by a significant part of the market.

13.5 Proposed non-reference services and ancillary fees

In addition to reference services, JGN offers non-reference services, legacy services for contractual transition and ancillary fees.

13.5.1 Non-reference services

JGN's non-reference services include:

- interconnection of embedded network service
- negotiated services.

In addition, JGN offers a framework for negotiation and dispute resolution for services that fall outside the scope of reference services and ancillary fees.

13.5.2 Contractual transition and legacy services

On commencement of JGN's proposed AA, the reference services offered under the current AA will not be available for new service requests. For delivery points which are already serviced by reference services, JGN expects all users to enter into a new Reference Service Agreement and to replace the old services with the new reference services provided under the proposed AA.

As discussed above, there are significant administrative efficiency gains to be realised through the simplification of services in this manner. JGN considers that these gains will support the NGO by lowering costs to retailers as users and ultimately to end users. Further gains will also arise from the enhanced consistency of gas network service delivery arrangements across Australian jurisdictions.

Facilitating transition

To facilitate the transition of delivery points from old AA services to new AA services, JGN has developed an effective transition mechanism to enable users to establish new reference services to existing delivery points from the commencement of the next AA period. This transition mechanism includes:

- *terms and conditions in the AA in an executable form* – On approval of the AA, existing users will have immediate access to a complete new form of agreement without the need for further commercial and legal development of individual contracts which should minimise administrative obstacles to access to new services and reduce transaction costs for users and JGN in establishing new agreements

- *bulk transfer provision within the Reference Service Agreement* – clause 11.4 of the proposed Reference Service Agreement provides the contractual mechanism for a complete and one-off transfer of delivery points from all of a user's existing reference service transportation agreements to a new Reference Service Agreement which is executable at a date of the user's choosing.

As a further benefit, the operation of the STTM will require changes to be made to existing network transportation contracts to provide "hub to point" haulage instead of "point to point" haulage services. Where users utilise the transition mechanism to establish new contracts from the commencement of the next AA then these users and JGN will avoid having to vary existing reference service contracts to accommodate the start of the STTM.

This single contractual transition for both reference service changes and STTM changes is fortuitous as it minimises the administrative and transaction costs associated with implementing both these changes.

For users that do not take timely advantage of the transition mechanism, JGN will continue to provide legacy services under existing reference service contracts. It will be necessary to negotiate variations to each of the remaining old reference service transportation agreements to maintain them in a form that is enforceable and commercially workable. Such variations would include:

- Setting the prices to be charged for the old services that reflect JGN's updated cost of service

- Updating contracts to allow the "hub to point" haulage service structure to interface with the STTM by enabling the receipt of gas at any receipt point

- Updating contracts for current laws.

JGN has set out in clause 2.6 of its proposed AA that it will, if necessary, provide legacy services to an existing user as a contingent measure where the user fails to effect the transition mechanism. JGN believes that the inclusion of a contingency approach for continuity of supply under existing services is consistent with the NGO as it is in the interests of JGN, users and end users to have transparency on the status and options of existing reference service transportation agreements after commencement of the new AA.

The pricing guide for legacy services provided in clause 2.6 is based on the average increase in rates calculated by JGN between 2010 and proposed for 2011, plus a 5 per cent premium. This premium provides a price incentive for users to make the intended transition to the new reference services and also to take some account of:

- the likely costs which would otherwise arise through increased complexity to administer and bill both the new reference services and the old legacy services alongside one another for some period of time instead of making a clean systems transition
- costs JGN would incur to negotiate updates to the legacy service terms for the factors listed above.

This premium is consistent with the NGO as it incentivises efficient behaviour and also helps to mitigate JGN's risks of additional costs arising through the commercial transition from old to new contracts due to user choices and behaviour.

Absent this incentive, all users would likely have to bear the additional costs associated with a potentially irrational decision by a given user to remain on the existing reference service transportation agreements. That is, those costs associated with dual billing arrangements and specific negotiation of the required updates to service terms.

JGN anticipates that a rational user would elect to transition to the new simplified service arrangements and make use of the bulk transfer provision to do so. On this basis, JGN has not forecast any users remaining on the legacy service for the purpose of cost allocations set out in section 13.7 or for determining the price path in section 13.8.

13.5.3 Ancillary fees

The ancillary fees relate to:

- *request for service* – This service is for collating the information provided and writing the letter of offer to a user or prospective user when they request a new, additional or changed service
- *special meter read* – This service is for reads requested by a user or prospective user rather than an ordinary read. This service must be scheduled with a minimum five day notice period
- *temporary disconnection* – This service is for disconnection of meters at the request of the user where temporary isolation of supply is required. The specific method used to ensure the isolation of supply is at the discretion of

JGN. The charge for temporary disconnection includes the cost of subsequent reconnection.

- *permanent disconnection* – This service is for disconnection of meters where the user requests that the delivery station is not to be moved or removed. The specific method of permanent disconnection is at the discretion of JGN who will ensure that the site is left in a safe condition. A request for reconnection must be made as a new connection request.

- *decommissioning and meter removal* – This service is for the permanent decommissioning of a network connection where a request is made for the removal of aboveground gas infrastructure. The specific method of disconnection is at the discretion of JGN who will ensure that the site is left in a safe condition.

13.6 Reasons for changes in reference services

JGN's proposed reference services (above) represent a refinement of its existing reference services. JGN has consolidated its reference services into one network haulage service and one meter data service instead of the previous seven different types of reference services (capacity reservation, managed capacity, throughput, tariff, multiple delivery point, gas swap and meter data service).

JGN has further sought to simplify its reference services by:

- grouping like services such as the haulage service and the meter data service

- using tariff classes instead of separate reference services to delineate between services to different types of customers.

The revised services provide a single haulage service with separate customer categories and tariff classes within this for volume and demand customers, instead of separate reference services for the contract market and for the tariff market.

JGN considers that simplifying its reference tariff offerings better supports the gas market objective as it reduces the administrative burden on gas market participants. Further, JGN's proposed reference services are better aligned with the service offerings of distributors in other jurisdictions. This is expected to make it easier for retailers to operate in multiple jurisdictions.

13.6.1 *Comparison to existing reference services*

Table 13-1 compares JGN's proposed reference services to its existing reference services.

Table 13-1: Summary of reference services

Proposed reference service	Existing reference service(s)	Reasons for change
Haulage service	Tariff service Capacity reservation Service Managed capacity service Throughput service Multiple delivery point Service	Simplification of reference services into the one new haulage reference service. This aids administrative simplicity and reduces transaction costs.
Meter data service	Meter data service	No change

JGN's gas swap service will no longer be offered because it is no longer necessary within the new market structure flowing from the introduction of the STTM.

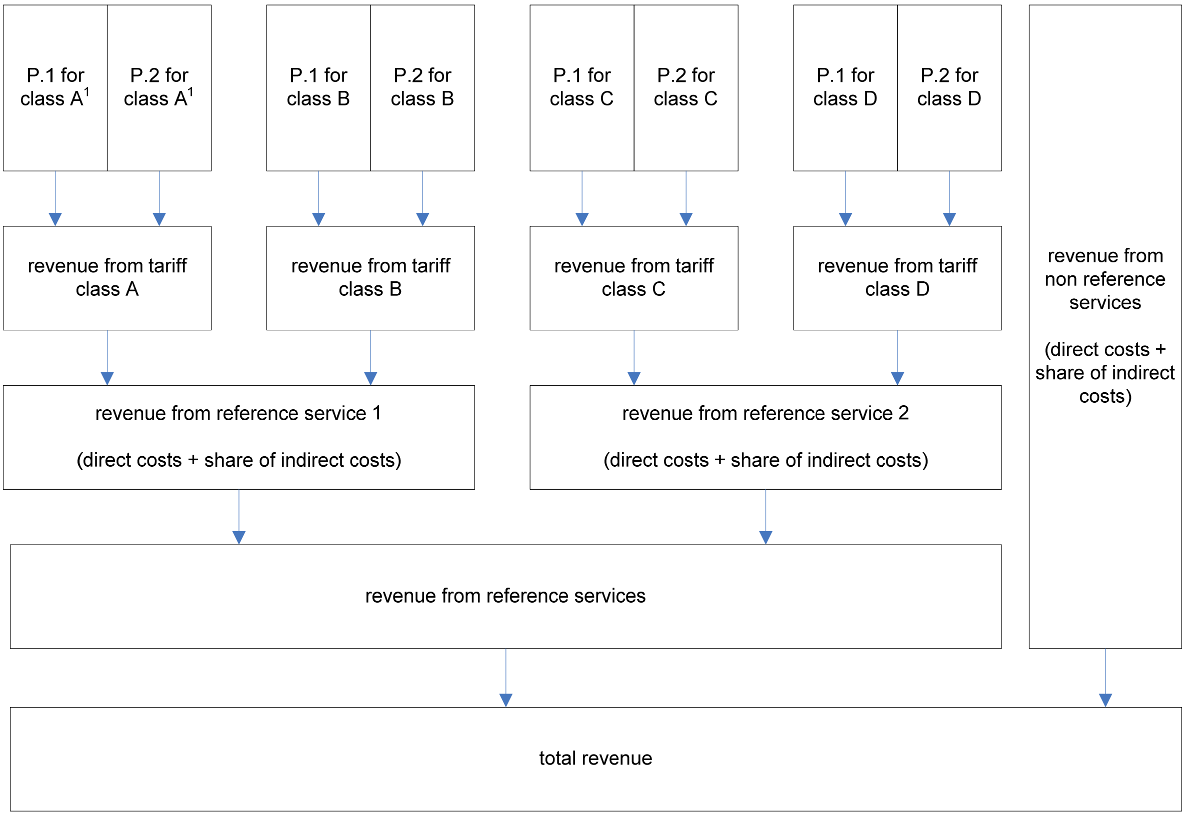
13.7 Cost allocation to services

The NGR require JGN to allocate its total revenues to its various reference and non-reference services. This section explains how JGN has performed this allocation, what 'allocation keys' or drivers it has relied upon and how the resulting allocations comply with the NGR requirements.

In developing its allocation methodology, JGN has relied upon guidance provided in the AER's AA Guideline.[71] Figure 13-1 is taken from that guideline. It sets out the total allocation process which runs from reference and non-reference services to total revenue.

[71] AER, *Access Arrangement Guideline*, March 2009.

Figure 13-1: Distribution cost allocation requirements



1. P.1 and P.2 are two different tariff or charging parameters charged to a class of users (tariff class A). Revenue from tariff class A may be obtained from two different sorts of charges (P.1 and P.2). These revenue sources comprise the revenue derived from tariff class A, which use, along with tariff class B, reference service 1.

Source: AER AA Guideline, March 2009, p. 69

13.7.1 Overview

JGN's cost allocation model takes the required cost of service (**COS**), deducts revenues associated with negotiated and ancillary services, and then allocates the residual costs to the haulage reference service and meter data reference service.

JGN calculates the revenue for other non-reference services, ancillary and negotiated, based on the level of activity for those services and their prices.

For the reference services, JGN divides the residual COS into its building block categories: return on asset, return of asset and operating costs. The model then splits these into operating cost allocations and capital cost allocations.

13.7.2 Capital allocations

The capital allocations consist of the return on assets and return of assets costs from the COS. JGN allocates these based on the share of the regulatory asset base attributable to each reference service.[72] This means JGN has used its asset categories as 'allocation keys'.

The haulage service comprises all regulatory asset classes except for the demand customer remote meter reading and communication devices which are allocated to the meter data service. This is because the costs of the network and meter provision are associated with the haulage service. The meter data service relates only to the provision of meter reading (an operating cost) and on-site data and communication equipment. Such equipment is only installed for large customer delivery points.

JGN considers small customer meter data loggers to be an integrated part of its network and has included this asset class in the haulage reference service allocation. This is because JGN would require these data loggers to operate its network even when meter data services are provided by another third party.

The model allocates the return on assets and return of asset costs to the asset classes using the written down value of the RAB and the depreciation by asset class. JGN considers these costs to all be direct costs associated with the identified asset categories.

13.7.3 Operating cost allocations

JGN allocates its opex costs to the haulage reference service and the meter data reference service differently for direct versus indirect costs.

JAM collects the direct operating and maintenance costs by activity. These are called work breakdown structure (**WBS)**. JGN's cost allocation model uses these JAM WBS cost collectors as allocation keys to allocate operating and maintenance costs to the haulage service and the meter data service based on the direct attribution of particular activities to each reference service. For WBS collectors which collect the costs of managers and other employees who work across multiple activities, these costs have been prorated across the haulage and meter data services using the weights from the directly attributable WBS collectors.

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[72] Note this share is a fully distributed cost allocation rather than the stand alone and avoidable cost allocations relied upon for assessing the efficient pricing bound of reference tariff classes in section 14.4.1.

JGN allocates the following direct costs to the haulage reference service:

- UAG costs including carbon permits for deemed fugitive emissions under the proposed CPRS
- mains tax
- marketing.

This is because these costs relate to the network and network usage rather than the provision of meter reading services.

For JGN's indirect costs, JGN makes a specific allocation to the meter data service, with the remaining costs allocated to the haulage service. JGN calculates the overhead allocation to the meter data service as follows:

Commercial in confidence

The residual indirect costs (including overheads and administration costs) are allocated to the haulage service.

13.8 Price path

This section sets out the proposed prices that will allow JGN to recover its required revenue as presented in chapter 12. Prices are determined in real 2010 dollars.

The comparison of total revenue to total cost of service is shown in Table 13-2.

Table 13-2: Revenue and cost alignment

	2010-11	2011-12	2012-13	2013-14	2014-15	NPV
Total cost of service	466.81	486.87	510.95	529.86	553.51	1915.72
Total revenue	471.45	485.52	506.50	530.20	553.54	1915.72

Note: The net present value (**NPV**) of JGN's total cost of service and total revenue is estimated using JGN's proposed pre-tax real WACC of 10.01 per cent.

Based on the cost allocation to the haulage reference service discussed above, JGN has solved for a price path that aligns the net present value (**NPV**) of its five year cost of service with the NPV of its forecast revenues. The resulting price path is set out in Table 13-3.

As discussed in chapter 5, the realignment of price to actual demand levels gives rise to a significant adjustment in 2010-11 prices. JGN estimates that 16 per cent of the average price rise between 2009-10 and 2010-11 is attributable to this demand reset.

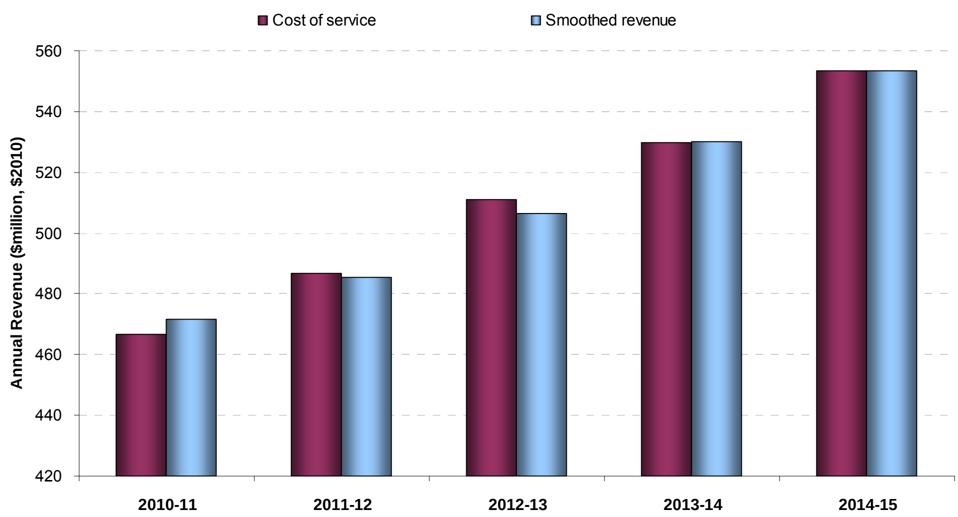
Table 13-3: Price path

	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15
Total revenue	400.20	471.45	485.52	506.50	530.20	553.54
Total demand (PJ)	93.20	96.02	96.63	95.76	96.84	97.70
Real average price ($/GJ)	4.29	4.91	5.02	5.29	5.48	5.67
Real price change		14.34%	2.34%	5.27%	3.51%	3.48%

Figure 13-2 illustrates how JGN's proposed price path tracks relative to its required revenues.

JGN has adopted this price path having specific regard to its cash flow requirements for the capital program over the next AA period.

Figure 13-2: JGN's smoothed revenue versus cost of service



13.9 RIN and rule 72 requirements

Table 13-4 sets out RIN and rule 72 requirements met in chapter 13.

Table 13-4: Summary of RIN responses

RIN/ rule 72 reference	RIN requirement	Where addressed in AAI
Pipeline and pipeline services		
RIN 2.2.1	In the access arrangement proposal submission: (a) Identify the pipeline to which the access arrangement relates and include a reference to a website at which a description of the pipeline can be inspected (b) Describe the pipeline services the service provider proposes to offer to provide by means of the pipeline (c) Specify the reference services in 2.2.1(b) (d) Outline and justify how the proposed pipeline services are those that are sought by a significant part of the market	(a) See Access Arrangement Section 1.3 (b) to (d) – section 13.4
Total revenue allocation		
RIN 2.5.2 Rule 72(1)(j)(i)	Provide in pro forma 9 the allocation of costs to services (a) Identify and quantify cost pools according to relevant asset classes and operating cost categories for the direct costs of reference services, the direct cost of pipeline services other than reference services, other costs from building block revenue and rebateable services (b) Reconcile total revenue for pipeline services allocated to reference services and other services	Building block regulatory model and pricing model Supporting information is set out in sections 13.7 and 13.8
RIN 2.5.2 Rule 72(1)(j)(i)	Provide in the access arrangement proposal submission (c) An outline of the nature of the allocation keys used to allocate relevant cost pools, explain why these allocation provide the best estimate and provide analysis to support their derivation (d) Supporting information and derivation for any allocation key use to allocate total revenue	Section 13.7
Revenue equalisation		
RIN 2.5.1	Provide the details contained in pro forma 8 to demonstrate that the net present value of the proposed revenue stream is equal to the net revenue stream generated from the building block approach for each reference service	Section 13.8 and pricing model

14 Reference tariffs

JGN has established a suite of reference tariffs to recover the costs it has allocated to its reference services. This chapter sets out JGN's proposal for referent tariffs and details how these comply with the relevant NGR provisions. It is structured as follow:

- *Section 14.1 Summary* – summarises JGN's reference tariff changes
- *Section 14.2 Law and ruler requirements* – identifies that JGN's tariffs and tariff class must have regard to the efficient pricing principles contained in the NGR
- *Section 14.3 Tariff classes* – shows how JGN has developed tariff classes that have regard to transaction cost and to customers ability to respond to differentiated price signals
- *Section 14.4 Efficient pricing* – demonstrates that JGN has set its reference tariffs to recover revenues that lie within the efficient pricing bounds of stand alone and avoidable costs. In doing so, JGN has had regard to its long run marginal cost
- *Section 14.5 Prudent discounts* – explains how JGN has selectively employed prudent discounts to avoid uneconomic bypass
- *Section 14.6 RIN and rule 72 requirements* – maps the RIN and NGR rule 72 requirements to the relevant sections and chapters.

14.1 Summary

JGN has maintained its existing reference tariff structures for all volume customers, which represent 88 per cent of revenue as at 31 March 2009.

JGN's remaining customers, who account for 12 per cent of JGN's revenue as at 31 March 2009, are on demand tariffs. JGN has restructured its demand tariffs to:

- recover trunk costs in a way that:
  - is consistent with the STTM hub arrangements and market definition
  - makes JGN indifferent to future sources of gas and transmission connection points

- avoids the situation where JGN's network prices drives separation in the wholesale gas price between coastal regions of Sydney, Wollongong, Central Coast and Newcastle

- removes perverse incentives at the volume/demand customer threshold by smoothing the pricing transition between these customer segments by introducing a minimum demand bill

- establish an interruptible supply tariff to facilitate load curtailment during supply constraint events.

14.2 Law and rules requirements

The NGR contain the following requirements with respect to reference tariffs:

- A tariff class must be constituted with regard to:
  - the need to group customers for reference services together on an economically efficient basis
  - the need to avoid unnecessary transaction costs.

- For each tariff class, the revenue expected to be recovered should lie on or between:
  - an upper bound representing the stand alone cost of providing the reference service to customers who belong to that class
  - a lower bound representing the avoidable cost of not providing the reference service to those customers.

- A tariff, and if it consists of 2 or more charging parameters, each charging parameter for a tariff class:
  - must take into account the long run marginal cost for the reference service or, in the case of a charging parameter, for the element of the service to which the charging parameter relates
  - must be determined having regard to:
    - (i) transaction costs associated with the tariff or each charging parameter
    - (ii) whether customers belonging to the relevant tariff class are able or likely to respond to price signals.

14.3 Tariff classes

As described in section 13.4, JGN proposes the following reference services:

- haulage service
- meter data service.

JGN has also proposed to retain ancillary services, as described in section 13.5.

For haulage and meter data services, JGN has established or refined existing tariff classes. These tariff classes enable JGN to achieve an optimal balance of differentiated price signalling, taking into account customer characteristics and the transaction costs of providing customised tariffs.

Introducing tariff classes for demand customers is an integral part of JGN abolishing certain contract terms for large customer reference services. It will provide increased efficiencies to users and customers through reduced administrative burden.

JGN proposes 26 tariff classes and distinguishes between two different customer categories:

- *volume (or small) customers* who include residential and small industrial and commercial customers
- *demand (or large) customers* who are larger commercial and industrial gas consumers.

Volume and demand customers are called 'tariff market' and 'contract market' customers in the current AA, respectively.

The distinction between volume and demand customers is based on the likelihood of their consumption being more or less than 10 TJ of gas per year. The 10 TJ threshold is used now by JGN, and is common in other jurisdictions. Larger customers must have a reasonable MHQ and MDQ specified per delivery point as they have a larger individual impact on the network than small customers.

14.3.1 Volume tariff classes

JGN's current AA assigns all volume customers to a single reference tariff class for the purpose of trunk network services and local network services.

JGN's proposed AA establishes two tariff classes for volume customers:

- *V-Coastal tariff* – Applicable to volume customer delivery points located in the Wilton network section, which is supplied from the JGN northern and southern trunks

- *V-Country tariff* – Applicable to volume customer delivery points located in country network sections that do not utilise JGN trunk mains.

This delineation is necessary to group country volume customers separately from volume customers located in the Wilton network section which includes the trunk mains. The delineation enables JGN to combine trunk charges with other network charges without affecting the tariffs that apply to country customer delivery points. The delineation enables JGN to combine trunk charges with other network charges without affecting the price paid by country customers.

14.3.2 Demand tariff classes

JGN's current AA charges for services to demand customer delivery points (denoted as contract customers in JGN's current AA) on a zonal basis, that reflects the customer's location within the local network. Retaining this approach gives rise to the 12 location-based demand tariff classes JGN is proposing.

Similarly, JGN has retained the option for throughput pricing for large customers as a separate tariff class (also for customers that are currently capped). JGN is also proposing an additional set of location-based capacity charge tariffs for very large customers who agree to participate as "first response" respondents in network load shedding events. JGN proposes to establish 24 demand tariff classes in the 2010 AA.

This proposal means JGN's demand customers will continue to be assigned to multiple reference tariff classes established by JGN to reflect their location within the local network, and the manner in which they are billed for usage.

Tariff categories

JGN demand tariff classes are grouped together by tariff category. There are three different categories for demand classes:

- *capacity* – This is the default category for demand customers. However, customers can select the other two available demand tariff categories at their option, subject to assignment procedures and criteria

- *capacity first response* – This is a new discounted tariff for large customers who are willing to participate in network load shedding on a "first response" basis. Assignment to these tariffs will be on user request where assignment criteria are satisfied. Customers assigned to this tariff category receive a discounted tariff in return for a commitment to shed load under an agreed curtailment plan. These customers must meet certain operational criteria relating to their usage and ability to shed load. This tariff category is intended to encourage more efficient and transparent load shedding

- *throughput* – Assignment to this tariff is currently made on user request. This tariff category replaces the capping and throughput service in the current AA and sets a ceiling for cost of network transportation that allows the price of gas to remain competitive with alternate fuels.

14.3.3 Transaction costs

JGN has considered transaction costs such as transportation costs, metering charges and administrative costs when determining its tariffs and tariff classes. JGN considers its decision to structure charges based on customer size (volume versus demand) is economically efficient for a number of reasons. For example, it would be inefficient for volume customers consuming less than 10 TJ a year to be charged on capacity as that would require more sophisticated daily metering. Such metering costs are avoided by charging these customers on throughput using basic metering equipment.

Similarly, transaction costs for volume customers are avoided by postage stamping their tariffs. It would be considerably more costly to charge these customers based on zonal location for limited benefit in terms of network savings arising from any demand response.

In comparison to the above, demand customers are charged on capacity as they have the necessary metering equipment for daily reads. In addition, unlike volume customers, demand customers are charged based on location. This is because:

- the size of the customers' usage and associated affects on the network warrant the additional costs of targeted price signalling (i.e. to manage capacity demands and network location decisions)

- this addresses the bypass risk that JGN may otherwise face because it does not have an exclusive franchise area.

The adoption of tariff classes for demand customers is an integrated and complementary component of a number of changes affecting services for large customers. Together, these result in greatly reduced transaction costs for retailers and customers. Transaction costs associated with complicated contract management and capacity booking management are also avoided through JGN's simplified reference services.

JGN considers that its tariffs and tariff classes provide the correct balance between minimising transaction costs and ensuring that customers have incentives to respond to pricing signals. Moreover, JGN considers that implementing of a tariff basket price control will better enable it to maintain this balance during the AA period.

14.3.4 Ability to respond to price signals

JGN's tariffs have been formulated with regard to how customers may respond to price signals. While volume customers are on postage stamped tariffs, demand customers' tariffs are dependent on location. This gives demand customers a clear signal that the location within the network of their premises will affect their payable tariff.

Minimum demand bill

JGN has also introduced a minimum bill charge for demand customers to provide a smooth transition in price between the volume and demand tariff classes.

JGN's 2005-06 to 2009-10 AA inadvertently established a perverse pricing incentive whereby some customers who moved from the volume to the demand market initially experienced a significant price reduction despite the increase in their capacity requirements.

JGN's proposed minimum demand bill addresses this incentive by ensuring customers shifting from the volume to the demand tariff class continue to face prices that reflect the costs these customers impose on the JGN network.

First response tariff

During emergency supply events which require network demand curtailment, the largest customers on the network inevitably bear the largest burden of the curtailment response. A new tariff is proposed for very large customers who are prepared to participate materially in load shedding at the first tier of load reductions, and to establish a formal plan with JGN for communication and target load reductions during an emergency event. A significant discount of 50 per cent is proposed for customers willing and able to react to a load shedding event as part of a “first response” tranche of reductions.

JGN considers that the transaction costs associated with this targeted tariff offering are warranted by the significant demand response that JGN can incentivise through this tariff.

14.4 Efficient pricing

14.4.1 Tariff efficiency

JGN has sought to establish efficient tariffs reflecting its different customer bases. In accordance with the NGR requirements, JGN has established its tariff classes and the tariffs it proposes for each of these to ensure that the expected revenue recovered for each tariff class for each reference service lies on or between stand alone and avoidable cost.

Background

Under the NGR, tariffs for distribution pipelines must satisfy rule 94(3) which requires expected revenue for each tariff class to lie between economically efficient bounds, specifically:

> for each tariff class, the revenue expected to be recovered should lie on or between:
>
> (a) an upper bound representing the stand alone cost of providing the reference service to customers who belong to that class
>
> (b) a lower bound representing the avoidable cost of not providing the reference service to those customers.

The purpose of applying stand alone and avoidable cost bounds on expected tariff revenues is to ensure that, for each tariff class, the distribution business is not pricing outside the bounds defined by economic efficiency. These stand alone and avoidable cost bounds are the highest and lowest theoretical prices that a distributor could charge a customer class without imposing costs on other classes. That is, pricing outside these efficient bounds implies cross subsidisation between customer classes if the business is recovering its costs.

Stand alone costs

Stand alone cost represents the cost that would be required to replicate or bypass the network. It follows that if customers were charged above stand alone costs, it would be beneficial for that group of customers to bypass the network, or to be provided by a new entrant, if entry is feasible. Therefore, these costs are comprised of the assets and operating costs that would be required to provide services to that tariff class.

To estimate the stand alone costs for each relevant tariff class JGN has relied on two optimised replacement cost (**ORC**) studies and its own operating costs. The first ORC study was carried out by JAM engineers for each non-country demand tariff zone prior to the last AA review. This represents the cost to replace the segment of the network considered without the benefit of scale that is achieved

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through a combined network. The second study is the ORC value determined for the entire network by IPART in 2000, which was considered when setting the initial capital base (**ICB**). This total network estimate is allocated between the volume market tariff classes using scalars to account for the benefits of scale.

To achieve an annual cost estimate that can be compared to expected revenues the following steps were undertaken:

- calculate the depreciation charge using the standard life for each asset class from the ORC estimated value
- multiply the remaining asset value by the WACC for a return on capital charge
- summarise the above two components with the estimated operating costs required to provide services to the relevant tariff class.

Table 14-1 presents the results for each tariff class. It can be observed that the estimate of stand alone costs far exceeds the expected revenue for each tariff class.

Table 14-1: Stand alone costs compared to expected revenue ($)

Tariff class	Stand alone estimate	Expected revenue
Demand market segment		
Sydney 1	39,209,191	3,838,870
Sydney 2	44,741,674	7,009,146
Sydney 3	47,789,555	10,453,339
Sydney 4	44,772,191	7,046,870
Sydney 5	36,928,541	1,943,249
Newcastle 1	46,610,033	3,108,463
Newcastle 2	51,832,372	2,559,764
Newcastle 3	33,013,329	627,872
Wollongong 2	23,852,334	767,203
Volume market segment		
Coast	694,180,069	376,507,594
Country	100,978,232	42,299,701

Avoidable costs

Avoidable cost represents the cost that would be avoided if the network business no longer provided services to that group of customers. If the business charges less than avoidable cost to that group of customers, it follows that it would be beneficial for it not to provide services to those customers, since the costs would be greater than the expected revenues.

Since customer numbers are a significant driver of operating costs, an incremental cost per customer was estimated in order to calculate an avoidable cost for each tariff class. This was estimated by dividing an estimate of operating costs that are driven by customer numbers and dividing by the number of customers. Although total operating costs are driven by customers a large proportion is generally fixed from year to year, such as property and management costs, whereas 'direct' operating costs, such as maintenance activities, will increase as customer numbers increase the size of the networks. That is, as each customer is added to the network another meter and service requires maintenance and after a certain number of customers are added more assets are added to the network which require maintenance.

In addition there are capital costs that are avoided when a tariff class was no longer supplied by the network business. Primarily those are the assets mentioned above, the meter and service. The capital costs associated with these costs (i.e., the return on and return of) is therefore included in the estimate of avoidable cost based on the relevant unit rate of providing a meter and service for each customer in the tariff class.

Table 14-2 presents the results for each tariff class. It can be observed that the expected revenue for each tariff class exceeds the estimate of avoidable costs.

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Table 14-2: Avoidable costs compared to expected revenue ($)

Tariff class	Avoidable estimate	Expected revenue
Demand market segment		
Sydney 1	326,438	3,838,870
Sydney 2	728,207	7,009,146
Sydney 3	870,501	10,453,339
Sydney 4	359,919	7,046,870
Sydney 5	92,072	1,943,249
Newcastle 1	242,736	3,108,463
Newcastle 2	200,885	2,559,764
Newcastle 3	33,481	627,872

Tariff class	Avoidable estimate	Expected revenue
Wollongong 2	92,072	767,203
Volume market segment		
Coast	244,570,587	376,507,594
Country	20,174,375	42,299,701

Summary

The efficient bounds for each tariff class are presented in the following figures.

Figure 14-1: Efficient bounds for expected revenues, demand tariffs

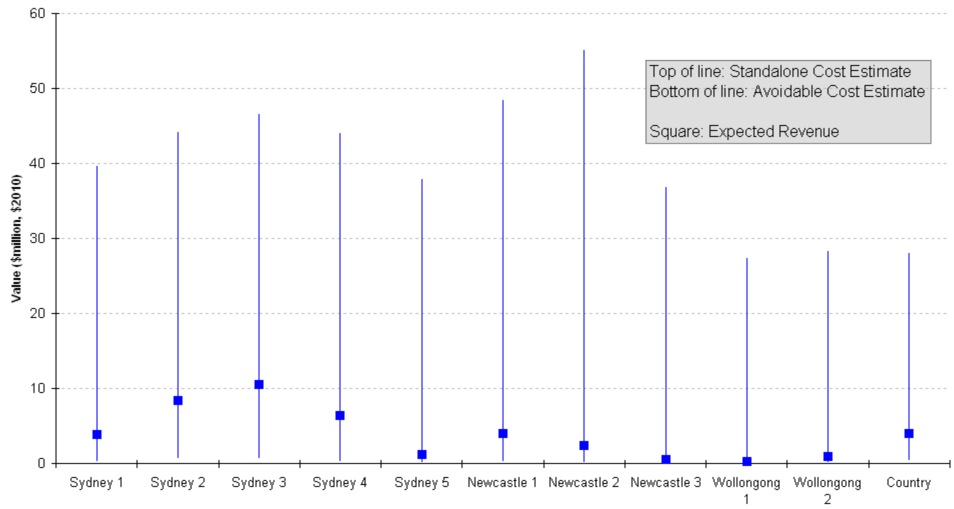
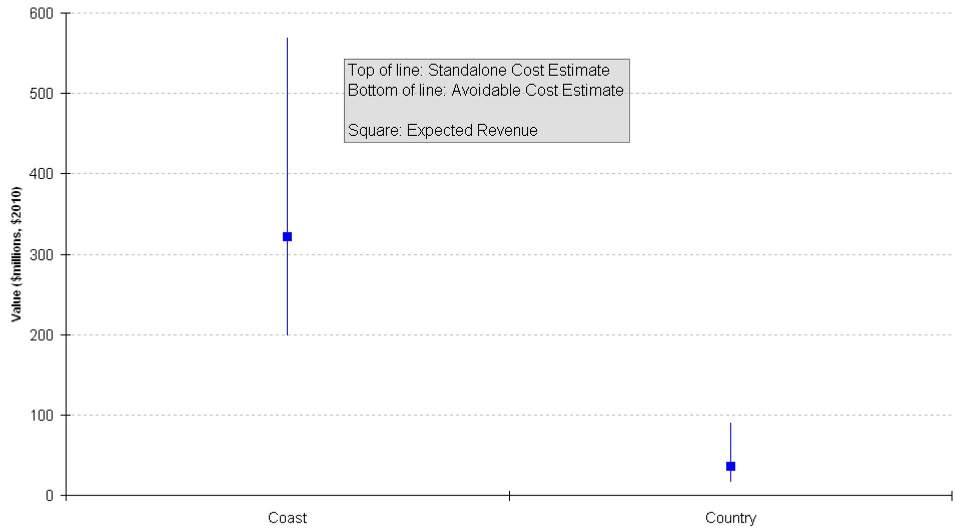


Figure 14-2: Efficient bounds for expected revenues, volume tariffs



14.4.2 Long run marginal cost

Under the NGR tariffs for distribution pipelines need to satisfy rule 94(4) which requires the distribution network service provider to consider long run marginal cost (LRMC) in setting tariffs, specifically:

> A tariff, and if it consists of 2 or more charging parameters, each charging parameter for a tariff class:
>
> > (a) must take into account the long run marginal cost for the reference service or, in the case of a charging parameter, for the element of the service to which the charging parameter relates;

Marginal costs represent the change in costs that arise from a change in demand. The types of costs that are captured are differentiated based on the time horizon that is under consideration, that is, whether it is the 'short run' or 'long run'. In the short run, investments in capacity and overhead is fixed and so marginal cost captures operational inputs such as additional labour, materials and energy. However over the long run all inputs can feasibly be altered such that marginal cost captures the cost of building additional capacity.

Marginal costs are essentially forward looking, since they reflect the expected change in costs that arise from changes in demand. Because they are forward looking invariably the estimates are subjective and are best viewed as a range.

Application of LRMC

The purpose of requiring tariffs and tariff parameters to be set by taking into account long run marginal costs reflects the economic principle that prices should reflect the underlying costs of providing the service. As consumption increases the capacity of the network requires augmentation to accommodate the additional demand. Therefore in order for consumption decisions to take into account these increased costs current prices need to reflect the expected additional costs arising from additional consumption.

Two factors affect the applicability of this logic to gas network pricing:

- the NGR permit JGN to recover its building block cost of services which includes a return on sunk costs and can therefore be expected to exceed LRMC – this point is acknowledged by NGR rule 94(6)

- JGN's capacity requirements are not driven so much by load peaks as by market expansion (i.e. new customers).

Gas networks are very different from electricity distribution businesses, which are subject to the same rule. Gas, and in particular in the JGN network, has lower penetration than electricity and faces competition from other fuel sources. In addition climate is a significant determinant of the customer mix and utilisation of the network. These factors affect the application of LRMC to signal the impact of incremental consumption since often in a gas network the objective is to *increase* consumption. Moreover, since the building blocks revenue is greater than LRMC not every tariff class and tariff parameter can be set with reference to LRMC and it would not be appropriate to do so.

For this reason and due to the affects of capital contributions on the LRMC on the demand customer category (see below) JGN estimated the LRMC only for the volume tariff classes since JGN believes these customers are driving incremental demand changes. Although this customer group is largely driving incremental demand it should be noted that JGN does not experience capacity constraints to the extent that electricity networks do. For this reason JGN is not subject to the same incentives to price throughput at LRMC. Therefore, the LRMC estimates are compared to the throughput charges since fixed charges are designed to recover costs on sunk assets.

Demand customers have large loads and are considered on an individual basis when they connect to JGN's network. Consistent with NGR rule 79(2)(b), these considerations examine the incremental revenues from the customer relative to the incremental costs. Where the expected costs exceed the revenues JGN charges a capital contribution to the connecting user.

The fact that these users pay a contribution for any capacity development costs not covered by JGN's existing charges, JGN's net LRMC can be expected to tend towards its prices for these users.

Approach

There are two commonly known approaches for estimating LRMC: the Turvey approach; and the average incremental cost (**AIC**) approach. The Turvey approach aims to capture the direct change in expenditure resulting from a change in demand whereas the AIC approach captures the average change in expenditure. For this reason the AIC approach is more readily applied and so for the purposes of this analysis JGN has utilised the AIC approach.

The AIC approach dictates that an optimal least cost capital programme and associated operating costs be forecast to meet additional demand over a medium term (20 to 30 years). JGN has utilised the capacity development component of its capex programme as it represents investment to accommodate changes in demand. JGN has estimated incremental operating costs using internal activity based cost information. These combined costs are then divided by the change in demand as forecasted by NIEIR to obtain a per unit estimate of LRMC.

Results

The LRMC estimate for the volume tariff classes ranges from $27/GJ to $33/GJ when the total costs are divided by the change in demand over the observed period. When JGN observes the annual changes in incremental costs and demand the LRMC during the forecast access arrangement period ranges from $13/GJ to $30/GJ with an average of $19/GJ. Extending the forecast period resulted in an average LRMC of $32/GJ. These compare to JGN's proposed volume haulage throughput tariff block 1 prices[73] of approximately $13/GJ.

Although JGN does not currently experience significant capacity constraints to warrant stronger price signalling this range demonstrates that JGN's prices are within the estimated range when the annual changes are observed. This means that tariffs are currently approximating the near term capital costs of additional capacity. Importantly the tariffs are at the bottom of the range such that should capacity constraints arise an increase in throughput prices would be consistent with JGN's estimated LRMC. When the LRMC is estimated over the entire period the range is higher than current throughput tariffs however this is consistent with the view that JGN's prices are currently designed to encourage consumption which is consistent with JGN's marketing strategy.

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[73] JGN has a further five blocks which have declining prices, and recover a further share of JGN's allowed costs.

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Consistent with NGR rule 94(6) JGN has sought to recover the residual of its costs in a manner that least distorts demand. This has involved JGN retaining standing charges for each customer.

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14.6 RIN and rule 72 requirements

Table 14-4 sets out RIN and rule 72 requirements met in chapter 14.

Table 14-4: RIN response

RIN/rule 72 reference	RIN Requirement	Where addressed in AAI
Tariff classes		
RIN 2.5.2.1	In the access arrangement proposal submission (a) Provide a description of each tariff class for each reference service	Section 14.3
RIN 2.5.2.1	(b) Explain how tariff classes identified in 2.5.2.1(a) are comprised for each reference service	Section 14.3
RIN 2.5.2.1 Rule 72 (1)(j)(ii)	(c) In explaining the response in 2.5.2.1(b) the service provider needs to provide information about the basis for grouping customers in a tariff class and how this grouping is economically efficient	Sections 14.3 and 14.4.1
RIN 2.5.2.1 Rule 72 (1)(j)(ii)	(d) In explaining the response in 2.5.2.1(b) the service provider needs to provide information about the type of transaction costs it has considered in determining tariff classes, what transaction costs are relevant to the proposed tariff classes and what transaction costs have been avoided. This explanation may include a quantification of the transaction costs that relate to the tariff class and those transaction costs avoided.	Section 14.3.3
RIN 2.5.2.1 Rule 72 (1)(j)(ii)	In the access arrangement proposal submission (e) Define the stand alone cost for each tariff class of each reference service which should outline what costs comprise the stand alone cost of providing each reference service to customers in each tariff class	Section 14.4.1
RIN 2.5.2.1 Rule 72 (1)(j)(ii)	(f) Define the avoidable cost for each tariff class of each reference service which should outline what costs comprise the avoidable cost of providing each reference service to customers in each tariff class	Section 14.4.1
RIN 2.5.2.1 Rule 72 (1)(j)(ii)	(h) Demonstrate that expected revenue recovered for each tariff class for each reference service lies on or between stand alone cost and avoidable cost	Section 14.4.1
RIN 2.5.2.1 Rule 72 (1)(j)(ii)	In the access arrangement proposal submission (i) Define long run marginal cost for each reference service or for each element of the service to which the charging parameter `relates, whichever is relevant. The definition of long run marginal cost needs to outline what costs comprise long run marginal cost	Section 14.4.2

RIN/rule 72 reference	RIN Requirement	Where addressed in AAI
RIN 2.5.2.1 Rule 72 (1)(j)(ii)	(j) Demonstrate how the relevant long run marginal cost has been taken into account in determining a tariff for a tariff class or the charging parameters within a tariff class. This may include a quantification of the long run marginal cost (and its components) that relate to the reference service or element of the reference service to which the charging parameters relate	Section 14.4.2
RIN 2.5.2.1 Rule 72 (1)(j)(ii)	(k) Explain how the tariff or charging parameters that comprise a tariff have been determined with regard to relevant transactions costs. In doing so, the service provider needs to provide information about the type of transaction costs associated with the tariff or charging parameters of the tariff. This explanation may include a quantification of the transaction costs that relate to the tariff class and those transaction costs avoided	Section 14.3.3
RIN 2.5.2.1 Rule 72 (1)(j)(ii)	(l) Explain how the tariff or charging parameters that comprise a tariff have been determined with regard to how customers may respond to price signals. This explanation should include analysis (preferably quantified) about customers' responsiveness to price signals relevant to the tariff or charging parameters.	Section 14.3.4
RIN 2.5.2.1	In the access arrangement proposal submission (a) Provide full details and justification of all prudent discounts. (b) Demonstrate that a discount is necessary to respond to competition or maintain efficient use of the pipeline. (c) Demonstrate (by quantifying the effect) that without the discount, reference tariffs would be higher than what they would be with the discount	Section 14.5 (confidential)

15 Price control formulae

JGN must propose a method to vary its prices over the AA period in order to:

- recover its revenue requirement as set out in chapter 12
- provide for adjustments to reflect inflation, tariff variation items such as UAG and, where relevant, pass through events such as changes in taxes.

This chapter sets out JGN's proposed price control formulae.

The chapter is split between the following headings:

- *Section 15.1 Summary* – summarises JGN's price control formulae
- *Section 15.2 Law and rules requirements* – The NGR require that a tariff variation mechanism aligns a networks revenues with the NPV of its approved revenue requirement
- *Section 15.3 Background and reasons for change* – JGN has previously faced limited ability to respond to market and demand developments within a given AA period which has contributed to an inability for it to recover what IPART determined to be its efficient costs, that is, its approved revenue requirement
- *Section 15.4 Haulage reference service* – JGN proposes to adopt a tariff basket form of annual tariff variation mechanism for its network services to improve its ability to maintain efficient price signals and to recover its required revenues
- *Section 15.5 Other reference services* – JGN proposes to retain the current fixed tariff schedule approach to annual tariff variation of its remaining reference services reflecting the relative stability in the markets for these services and the administrative simplicity of this approach
- *Section 15.6 RIN and rule 72 requirements* – maps the RIN and NGR rule 72 requirements to the relevant sections, chapters and regulatory models.

15.1 Summary

JGN earns its revenue and provides for adjustments in its current AA through a schedule of prices which it varies each year for inflation and UAG.

For the next AA period, JGN will adopt a tariff basket form of price control for its haulage reference service which provides 90 per cent of JGN's revenues. Unlike a fixed tariff schedule, a tariff basket sets formulae governing annual tariff movements which JGN must comply with.

JGN proposes to retain a fixed tariff schedule approach for its meter data reference service that does not relate to haulage. This reference service accounts for only 1.3 per cent of JGN's revenues as at 2010-11 and does not warrant a more complex form of annual tariff variation.

This tariff basket approach will better enable JGN to respond to market developments and retain efficient price signals over the life of the AA. Further, it will bring JGN's method of annual tariff variation into line with the current practice in most[74] gas networks. JGN considers that these outcomes support the national gas objective and that its proposed tariff basket complies with the relevant NGR requirements.

15.2 Rule requirements

Rule 92 of the NGR requires that:

- a full access arrangement must include a mechanism, referred to as the reference tariff variation mechanism, for variation of a reference tariff over the course of an access arrangement period
- the reference tariff variation mechanism must be designed to equalize in terms of present values:
    - (a) forecast revenue from reference services over the access arrangement period
    - (b) the portion of total revenue allocated to reference services for the access arrangement period.

Rule 97 of the NPG elaborates on this requirement by setting out that:

- a reference tariff variation mechanism may provide for tariff variation using a schedule of fixed tariffs, a formula set out in the access arrangement, a cost pass through, or some combination of these methods

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[74] Five of eight gas distribution network access arrangements JGN has assessed include tariff basket forms of price control. The five tariff based networks include Envestra Vic, Envestra Albury, SP AusNet, Multinet and Envestra SA. The remaining three that had fixed schedules were ActewAGL, Envestra Qld and Allgas.

- a formula for tariff variation may provide for variable caps on the revenue, a tariff basket price control, a revenue yield control, or some combination of these

- in deciding whether a particular reference tariff variation mechanism is appropriate to a particular access arrangement, the AER must have regard to:

  (c) the need for efficient tariff structures

  (d) the possible effects of the reference tariff variation mechanism on administrative costs of the AER, the service provider, and users or potential users

  (e) the regulatory arrangements (if any) applicable to the relevant reference services before the commencement of the proposed reference tariff variation mechanism

  (f) the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction)

  (g) any other relevant factor

- a reference tariff variation mechanism must give the AER adequate oversight over tariff and except as provided by a reference tariff variation mechanism, the mechanisms must not to vary during the course of an AA period.

JGN has sought to propose a reference tariff variation mechanism for each reference service which:

- complies with these rules

- has regard to the characteristics of the markets, demand for the relevant reference service, and the relative costs and benefits of tariff variation complexity versus simplicity for each reference service.

In doing so, JGN considers that its proposed mechanisms are consistent with the revenue and pricing principles of the NGL and better support the national gas objective than existing mechanisms.

15.3 Background and reasons for change

During the 2005-06 to 2009-10 AA period, JGN has operated under a schedule of fixed tariffs as its form of annual tariff variation mechanism. As discussed in chapter 4, over this period JGN has experienced demand that was significantly less than approved by IPART. In conjunction with an inability to adjust its reference tariffs over the AA period, this demand outcome contributed to JGN receiving less than its efficient costs—that is, the COS or revenue requirement determined by IPART.

This outcome is inconsistent with rule 92(2) above and with the NGL pricing principle that a network should able to recover at least its efficient costs.

Matters which JGN could have responded to if allowed this flexibility include the demand effects of government energy efficiency policies, water savings initiatives, and anticipated carbon pricing.

These dynamic market factors will continue, yet in addition to the risk of volume/forecast, other external and market factors can compromise the interests and objectives of price efficiency and recovery of costs. Together, these factors and uncertainty drive a need for JGN annual tariff variation mechanism to include scope for JGN to add, remove and fine tune its tariffs.

JGN has had regard to the above issues that have arisen under the existing tariff variation arrangements consistent with rule 97(3)(c) and considers that conditions that impeded the ability of those arrangements to work effectively will persist into the future. For these reasons, JGN's decision to implement a tariff basket approach is made with a view to the long term - the coming AA period and beyond. It will provide JGN with a level of flexibility and responsiveness to support efficient price signals during the AA period consistent with rule 97(3)(a). Examples of medium and long term issues that may require a responsive approach to pricing include:

- *CPRS* – may have significantly different impacts on different market segments
- *emissions trading* – price and market structure likely to change
- *national energy customer framework* – may need to plan to align to different customer categories and different cost drivers due to future statutory requirements
- *competition* – from alternative fuels and appliance technology.

The tariff basket approach maintains consumers long term interests by always balancing to the weighted average price. This principle is well established in electricity and other gas jurisdictions and JGN's proposal to adopt this approach is therefore consistent with rule 97(3)(d). A tariff basket approach also supports JGN's long term interests by allowing JGN to be responsive to market changes during the AA period and thereby maintain efficient tariff structures consistent with rule 97(3)(a).

15.4 Haulage reference service

15.4.1 Tariff variation mechanism

For its haulage service, JGN proposes a tariff basket annual tariff variation mechanism as permitted under rule 97(2)(b) in the form of a weighted average price cap (**WAPC**) formula. JGN will implement this WAPC using the CPI-X price control formula and Annual Tariff Variation Mechanism specified in clause 3.5 of the AA.

The weighted average price element of the tariff basket formula is given effect through the following parameters that comprise the right hand side of the WAPC:

$$\frac{\sum_{x=1}^{n}\sum_{y=1}^{m} p_t^{xy} q_{t-2}^{xy}}{\sum_{x=1}^{n}\sum_{y=1}^{m} p_{t-1}^{xy} q_{t-2}^{xy}}$$

These parameters determine the weighted average of notional revenues in the current year compared to the year in which the proposed tariffs are to apply. This notional revenue relies upon historic quantities from two years prior. This is consistent with the practice in other jurisdictions and allows the price control to rely on actual rather than estimated quantity data.

JGN considers that relying on actual rather than estimated quantity data is consistent with rule 97(3)(b) because it reduces the administrative burden on the AER relative to the alternative of using estimated data for this purpose.

The price cap element of the WAPC is given effect through the following formula which comprises the left hand side of the WAPC:

$$(1+CPI_t)(1-X_t)V_t$$

The X_t parameter is set at -1.96% and is required to give effect to the price path set out in section 13.8 and thereby align the NPV of JGN's cost of service with its forecast revenues.

The CPI_t parameter allows JGN's haulage reference tariffs to be adjusted annually for inflation.

The V_t parameter is the annual variation factor required to give effect to the annual tariff variations of UAG and weather correction set out in section 16.5 as well as the proposed pass through events set out in section 16.6, for those years in which pass through events occur. This parameter is required to transpose the required nominal value of tariff adjustments into a percentage variation factor for use in the left hand side of the WAPC.

This tariff basket combines both annual price path variation with pass through variation consistent with rule 97(1)(d). It will apply to all JGN's haulage reference tariffs for all tariff classes.

15.4.2 Tariff variation process

JGN will submit its annual reference tariff proposal to the AER for approval 30 business days prior to the relevant financial year in which the proposed tariffs are to apply. JGN's annual reference tariff proposal will include a pricing model that demonstrates JGN's compliance with the tariff variation mechanism.

Submission of a formulaic model is intended to minimise the administrative burden on the AER consistent with rule 97(3)(b). It will provide an objective and transparent means for the AER to exercise its oversight and powers of approval over reference tariff variation consistent with rule 97(4).

The AER will review this proposal for compliance with the tariff variation mechanism and approve or reject the proposal consistent with the AA terms.

JGN considers that this approach provides a transparent and administratively efficient process for annual tariff variation. It aligns with the equivalent processes in a number of jurisdictions consistent with rule 97(3)(d).[75] This alignment supports improved consistency across Australian jurisdictions and across gas and electricity, consistent with the recommendations of the Ministerial Council on Energy's expert panel.[76]

Given that JGN must demonstrate compliance with the price control formula, JGN does not consider that this approach will impose any additional administrative burden on the AER relative to the annual reference tariff approval process contained in JGN's current AA.

15.4.3 Transitional measures

To accommodate the introduction of the tariff basket price control, JGN has established a range of transitional measures. JGN has detailed these in Appendix 15.1 and 15.2 and has designed them to ensure JGN can apply the tariff basket price control formula in each of the transitional years.

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[75] including Victorian gas and electricity, SA gas and electricity and NSW electricity.

[76] Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006.

JGN is proposing new reference services that aggregate a number of existing reference services as set out in section 13.6.1. JGN is also restructuring certain aspects of its existing pricing regime for some tariff classes (e.g. the trunk element of demand customer charges). Together with the fact that JGN does not currently have a tariff basket form of price control, these factors mean that JGN must establish 'launch tariffs' that match the new services and structure while reconciling to current revenues

The proposed price control (like that applied in most jurisdictions that have a WAPC) relies upon historic demand data from two years prior (year *t-2*) to provide the weights in the WAPC formula. It also relies on historic price from the year prior (year *t-1*) to assess the price movements into the year of the proposed prices (year *t*).

Because JGN does not have current prices and demand in the format required, it has developed a set of launch tariffs for 2009-10 to give effect to the WAPC.

JGN has developed this proxy data in a manner that reconciles to current tariffs, to prove that these transitional measures do not give rise to any windfall gains or losses (i.e. they are revenue neutral). JGN's launch prices are those proposed for 2010-11 as set out in schedule 2 of the AA. Confidential Appendix 15.1 provides the launch tariffs and documents the reconciliation to current prices

Confidential Appendix 15.2 provides the launch demands required for 2010-11 and shows how these reconcile to the NIEIR demand forecast set out in chapter 4. Because JGN will not have historic actual demand data for year *t-2* until 2012-13, JGN proposes to use the 2010-11 demand data submitted in its pricing model and relied upon to determine the X factor price path as a proxy for *t-2* for the purpose of applying tariff the tariff variation mechanism to set 2011-12 prices

15.5 Other reference and non-reference services

JGN proposes to maintain its prices for meter data reference services and ancillary services in real terms over the 2010-11 to 2014-15 AA period.

15.5.1 Tariff variation mechanism

JGN will retain a tariff schedule approach for its meter data reference services and ancillary services. This approach involves JGN publishing a list of real prices for each year of the 2010-11 to 2014-15 period in its AA and then adjusting this each year for inflation.

Schedule 2 of JGN's AA sets out the proposed real tariff schedule for each of the:

- meter data reference services

- ancillary fees.

15.5.2 Tariff variation process

The tariff variation process will follow JGN's haulage reference tariff variation process. JGN will submit its annual tariff proposal including a pricing model that demonstrates how JGN has escalated the real tariffs published in its AA for inflation. The AER approval will be based on its confirmation that JGN has correctly applied inflation adjustment to its tariffs.

15.6 RIN and rule 72 requirements

Table 15-1 sets out RIN and rule 72 requirements met in chapter 15.

Table 15-1: RIN response

RIN /rule 72 reference	RIN requirement	Where addressed in AAI
Tariff variation mechanism		
RIN 2.5.4.1 Rule 72(1)(l)	In the access arrangement proposal submission (a) Outline the proposed reference tariff variation mechanism and the basis for any parameters used in the mechanism.	Sections 15.3, 15.4 and 15.5
RIN 2.5.4.1 Rule 72(1)(l)	(b) Justify the reference tariff variation mechanism and address the factors contained in Rule 97(3) Note: In doing so the service provider needs to establish a materiality level for events that will be passed-through for the AER to have regard to the possible effects of the reference tariff variation mechanism on the administrative costs of the AER, the service provider and users or potential users.	Sections 15.3, 15.4 and chapter 16
RIN 2.5.4.1	(c) Outline how the reference tariff mechanism gives the AER adequate oversight or powers of approval over variation of the reference tariff (Rule 97(4)) Note: In order to address the requirements in Rule 97(4) the service provider will need to outline the administrative arrangements for periodic reviews of tariffs including timing of notifications to the AER.	Sections 15.4 and 15.5. AA clauses 3.4 and 3.5

16 Pass through events and mechanisms

NGR rule 97 allows JGN to propose the mechanism for implementing existing pass through events as well as proposing new pass through events. These mechanisms give JGN the ability to manage its risk exposure for matters that are:

- outside its control
- too uncertain to prudently forecast
- high potential cost, but low probability events.

JGN has sought to specify prudently its assumptions and pass-through arrangements to ensure the effectiveness of the AA over the next AA period. This chapter sets out JGN's proposed pass through events and mechanisms.

This chapter is structured as follows:

- *Section 16.1 Summary* – summarises JGN's proposed treatment costs associated with uncertain events
- *Section 16.2 Law and rules requirements* – identifies the rule requirements allowing pass throughs within JGN's annual reference tariff variation mechanism
- *Section 16.3 Current AA* – describes JGN's current range of annual tariff variation factors and pass throughs
- *Section 16.4 Criteria for assessing pass through events* – sets out the criteria JGN has considered to establish its proposed annual tariff variation factors and pass throughs
- *Section 16.5 Annual tariff variation factors* – details JGN's proposed tariff variation factors
- *Sections 16.6 Proposed pass through events* – sets out JGN's proposed pass through events
- *Section 16.7 RIN and rule 72 requirements* – maps the RIN and NGR rule 72 requirements to the relevant sections and chapters.

16.1 Summary

The following table sets out events for which JGN has assessed the probability or impact as being too uncertain to forecast reasonably in its AA, and JGN's proposed treatment under a tariff variation or pass-through mechanism.

Table 16-1: Summary of JGN's approach to managing highly uncertain risk events

Event	Where described in AAI	Costs potentially affected
Annual tariff variation		
Unaccounted for gas	Sections 6.5.4 and 16.5.1	Opex
Licence fees and statutory charges	Section 16.6.2	Revenue recovery
Weather events	Sections 5.8.1 and 16.5.2	
Pass through events		Cost of capital
Change in tax	Section 16.6.1	Opex
Regulatory events:		Opex and / or capex
National Energy Customer Framework	Section 16.6.4	
National Gas Connections Framework	Section 16.6.5	
Australian Energy Market Operator	Section 16.6.6	
Short term trading market	Section 16.6.7	
Financial failure of a retailer (credit support)	Section 16.6.8	
Retailer of last resort (**ROLR**) event	Section 16.6.9	
Business continuity	Section 16.6.10	

The formulae to give effect to these annual tariff variations and pass through events are detailed in the reference tariff policy section of JGN's AA. JGN considers that implementing its proposed pass throughs through the tariff based form of WAPC set out in section 15.4.1 will best enable it to implement pass throughs in a manner that maintains efficient tariff structures consistent with rule 97(3)(a). JGN proposes that the AER's pass through oversight and approval would be conducted as part of the annual tariff approval process described in section 15.4.2 and as set out in the reference tariff policy section of its proposed AA.

16.2 Rule requirements

Rule 97(c) of the NGR allows JGN to propose a variation to reference tariffs as a result of a cost pass through for a defined event. Rule 97 also allows JGN to propose a mechanism for implementing cost pass through. The AER's RIN provided to JGN and the AER's AA guideline both provide further detail on the information the AER requires to consider pass through proposals.

16.3 Current access arrangement

JGN's current AA identifies four pass through events for which JGN may seek to recover costs:

- *a change in tax event* – a new tax, or changes in the rates of tax or calculation of taxes that affect JGN's costs
- *a regulatory event* – changes in the obligations affecting JGN's operations, market interactions or applicable license fees and statutory charges
- *guaranteed customer service level standards* (**GCSS**) – costs arising from a Ministerial decision to impose guaranteed service level standards and payments in NSW
- *unaccounted for gas* – while defined as an incentive mechanism, UAG cost recovery has been operating as a cost-pass through up to the target UAG rate discussed in section 6.5.4.

16.4 Criteria for assessing pass through events

JGN has considered the following criteria and information in order to determine which costs and events to propose as pass throughs and which are best included in JGN's proposed opex forecasts:

- Can the event be reasonably foreseen?
- Are the details of the event firmly defined to enable JGN to establish confidently a cost forecast?
- Does a pass through already apply consistent with rule 97(3)(c)?
- Does the pass through constitute an annual tariff variation factor?

JGN has categorised its pass through events as either:

- annual tariff variation factors that occur as a matter of course under the annual tariff variation mechanism and tariff approval process

- pass through events which occur on an 'as required' basis, albeit that their pass through may be implemented at the time of annual tariff changes where this does not threaten JGN's financial viability.

The events which JGN has defined in its AA as annual tariff variation factors and pass through events are described below.

16.5 Annual tariff variation factors

JGN's annual tariff variation factors are set out in its price control formula in the reference tariff policy section of its proposed AA and are discussed below. JGN proposes that its annual tariff variation factors do not have a materiality threshold. This is because these factors will be implemented as part of the already scheduled annual tariff variation process and therefore do not impose any incremental costs on JGN or the AER consistent with rule 97(3)(b). Further, JGN's current annual variation for UAG does not have a tariff materiality threshold consistent with rule 97(3)(c).

16.5.1 Unaccounted for gas

JGN must pay for gas that is lost due to metering error or system losses, called unaccounted for gas. These costs are an operating expense to JGN as set out in section 6.5.4. Although some losses are within JGN's control, others are not and are a normal part of business.

Under its current AA, JGN recovers the forecast cost of UAG for any year as the product of:

- forecast gas throughput for the year

- forecast price for purchasing gas

- an allowed UAG benchmark of 2.1 per cent.

However, because JGN cannot easily accurately forecast the actual gas throughput and gas price, it is allowed under the current AA to pass through variations between forecast and actual throughput and prices with no materiality threshold.

JGN proposes retaining a mechanism that permits JGN to recover changes in its UAG costs relative to those included in the forecast cost of service. In this AA JGN proposes that this includes recovery of:

- the difference between actual and forecast (allowed) gas throughput and competitively procured gas prices for a given year
- the difference between actual UAG (as a percentage of actual gas throughput) and the benchmark UAG so long as actual UAG is within a target range of 2.1 per cent to 2.7 per cent.

This mechanism will also cover unforeseen changes in the wholesale price of gas due to CPRS costs. This is consistent with pass through arrangements in JGN's current AA which allow it to recover its costs based on its actual gas price.

Climate Change Policy and Implementation

Climate change policy has considerable uncertainty. The Commonwealth Government plans to mitigate the effects of climate change using two policies:

- CPRS
- RET.

Both policies are still developing and are likely to have material impacts on JGN's business, but the actual overall impact is unknown.

As described earlier in this AAI, JGN has attempted to account for certain effects of the CPRS on its costs by means of:

- inflating input costs by the pass through of carbon pricing in business inputs such as labour, steel and plastic discussed in section 6.4.3
- allowing for the purchase of carbon permits to offset fugitive emissions discussed in section 6.5.4.

However, these estimates do not account for other potential impacts of the CPRS, including:

- increased costs of complying with CPRS such as monitoring, reporting and auditing carbon emissions
- buying carbon permits directly to offset JGN's carbon footprint.

Therefore, JGN has included within its UAG pass through parameter recovery of its carbon permit costs.

To the extent that JGN also incurs unforeseen non-permit costs, these would be recovered under the regulatory change event pass through discussed in section 16.6.4.

16.5.2 Weather effects

As discussed in chapter 5, JGN's gas consumption for the volume customer category is highly sensitive to weather effects. The demand forecasts in an AA flow through to allowed tariffs and ultimately to the revenues recovered. These demand forecasts assume a certain number of HDD in each year, as described in section 5.8.1. In the current AA period, JGN's revenues have been lower than forecast due to HDD forecasting error. JGN cannot control weather and should not be required to accept economic loss arising from HDD forecast error.

Having had regard to the inadequacy of current arrangements consistent with rule 97(3)(c), JGN proposes a symmetrical mechanism which adjusts for over and under forecasting of HDD. This mechanism is formulaic and relies upon actual BOM data to identify divergence between forecast and actual HDDs and the tariff adjustment required to compensate for this. The formulaic nature of the mechanisms and reliance of independently observable BOM data is intended to minimise the administrative burden on the AER consistent with rule 97(3)(b).

JGN proposes an adjustment factor in its tariff basket price control formula that adjusts for the difference between the number of HDD assumed in the demand forecast underpinning JGN's tariffs and the actual HDD that occur. This is similar to the UAG adjustment in that it adjusts annually for uncontrollable cost affects on the JGN network.

JGN considers that this mechanism will help ensure JGN is able to at least recover its efficient costs consistent with the pricing principle in NGL s.24(2).

16.6 Proposed pass through events

JGN has applied the assessment criteria to identify the proposed pass through events described below. For each of these pass through events JGN would employ the relevant pass through factor within its proposed tariff basket price control formula. This mechanism would translate a nominal dollar value into a required percentage adjustment to the weighted average tariff basket. It would then 'back-out' this amount in the following year. JGN also seeks the flexibility to smooth price shocks arising from pass through adjustments through use of a tariff basket form of WAPC.

To minimise administrative burden on the AER, JGN, users and end users, JGN proposes to include pass throughs within its annual tariff variation mechanisms and include financing costs to account to the lag in recover of the pass through event costs. JGN considers that this approach best supports compliance with rule

97(3)(b). This means that there is minimal incremental administrative cost because these pass throughs would occur within the already scheduled annual tariff approval process. Consequently, JGN considers that no materiality threshold should be applied where pass through events are recovered in this manner.

Notwithstanding the above annual possible pass through process, JGN notes that the cash flow effects of certain pass through events may be so severe as to potentially jeopardise JGN's financial viability. In these limited instances, JGN proposes that within-year pass throughs be permitted and that the AER uses its reasonable discretion to assess materiality.

16.6.1 Change in tax event

Changes in taxes are a cost to JGN, but are outside its control. In many cases, JGN cannot accurately forecast these changes or affects on its costs and demand. Moreover, JGN cannot manage taxation risk associated with changes in statutory rates or calculation methods for various State and Commonwealth taxes.

JGN proposes a pass through for any material costs or savings from a change in tax event that is outside of its control, including:

- a change in the way or rate at which a tax relevant to JGN's costs or revenues is calculated
- the removal or imposition of new (relevant) taxes.

A change in tax event which cannot be foreseen or forecast is a pass through event in JGN's existing AA.

16.6.2 License fees and statutory charges

Over the next AA period, JGN must pay licence fees and statutory charges to NSW and national bodies, including but not limited to:

- IPART authorisation fee
- AEMO
- the STTM
- local councils mains tax.

Over the next AA period, some of these fees and charges may vary significantly as economic and market regulation transitions to national bodies.

Because these fees and charges are outside of its control, JGN should not bear the risk from inaccurate forecasting of these costs. The current AA allows for pass through of these costs. JGN proposes the continuation of passing through all licence fees and statutory charges to customers as uncontrollable opex.

16.6.3 Regulatory events

A regulatory event which cannot be foreseen with sufficient detail to develop adequate forecasts is a pass through event in the current AA.

JGN currently faces changes in obligations affecting its operations, market interactions and (potentially) applicable license fees and statutory charges. It will also be subject to unforeseen requirements mandated by a regulatory authority, market administrator or government edict, including but not limited to:

- national energy customer framework
- national framework for natural gas customer connections
- AEMO
- short term trading market
- financial failure of a retailer
- ROLR event
- business continuity event
- climate change policy and implementation costs.

JGN cannot predict these events with sufficient confidence to develop adequate forecasts of its costs, demand and business operations.

Following is a summary of the potential regulatory events and their associated costs.

16.6.4 National energy customer framework

The proposed NECF is described below. The major uncertainties for JGN's AA are:

- the timing of the NECF
- the final content of the NECF
- its potential impact on existing access arrangements and/or those in the course of review.

Timing

According to the most recent MCE communiqué, it is intended to introduce the NECF legislation into the spring 2010 session of the South Australian Parliament.[77] This suggests a January 2011 implementation, by which time a revised AA for JGN will be operating.

Content

So far, the MCE/SCO has released only a first exposure draft of the National Energy Retail Law (**NERL**) and associated Rules and regulations[78], which is acknowledged to be incomplete in major respects. A second exposure draft is proposed for late 2009. Given experience from past consultations, JGN fully expects that these instruments will be subject to ongoing consultation and debate. This will add to the difficulty of forecasting what impacts the NECF may have on JGN costs over the next regulatory period.

Impact

It is not clear from MCE/SCO consultations so far how the new framework will sit with either established gas access arrangements or those in the course of review such as JGN's. MCE/SCO has referred to the need for a 'managed transition' from existing arrangements, but has provided no firm details for such a transition.

At the same time, MCE/SCO has recently indicated that it is up to jurisdictions to decide how and when the NECF will be implemented.[79] JGN notes that the latest MCE meeting has set in train a process for jurisdictions to begin to develop implementation plans, but that any statement on progress in this area appears to be at least six months away.[80]

Background to the NECF

The NECF has been under development since 2004 by a national retail policy working group (**RPWG**).[81]

The NECF seeks to put in place a new national set of obligations on both retailers and distributors which will establish rights and protections for small retail customers. Both residential and business retail customers will be covered. The

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[77] Ministerial Council on Energy, *Communiqué*, Darwin 10 July 2009, p. 2.

[78] Released on 30 April 2009.

[79] Ministerial Council on Energy Standing Committee of Officials: *First Exposure Draft Law and Rules - Explanatory Memorandum*, 30 April 2009, p. 2.

[80] Ministerial Council on Energy, *Communiqué*, Darwin 10 July 2009, p. 2

[81] A sub group of the MCE's Standing Committee of Officials (SCO). This description of the NECF is drawn from the Explanatory Memorandum released on 30 April 2009.

obligations on distributors (both gas and electricity) will be expressed as a 'standard distribution contract' in a schedule to the rules. This contract will be deemed to apply, and compliance will be mandatory.

At the same time, the framework will also seek to establish a new formalised process for distributor relationships with large customers to be approved by the AER.

There will also be an obligation on gas distributors to adopt mandatory minimum provisions in the NGR when entering into a 'gas service agreement' with a retailer.[82] These obligations are referred to as 'retail support clauses' (**RSC**). They will form part of the distributor's obligations over an access arrangement. It will be possible for a retailer and distributor to negotiate other matters, but the minimum mandatory clauses must apply.

The legal architecture for the NECF proposed by RPWG is a NERL which will be stand alone legislation, accompanied by National Energy Retail Rules (**NERR**).

The RPWG envisages a significant role for the AER under this framework. The AER will be bound by the retail support contractual clauses in approving access arrangements. The AER will also:

- approve any proposed standard contracts for large customers in place of the contract applicable to small customers
- have a general enforcement role similar to that in the NGL but extended to include enforceable undertakings and remedies for non-compliance
- have a major role in compliance monitoring and reporting
- the RPWG is also proposing civil penalty regime to deal with non-performance under a distributor's standard distribution contract and the gas service agreement.

The RPWG has indicated that there will be no liability cap for negligence. This opens up a major exposure for distributors should a rare, but possible, catastrophic event occur.

JGN issues for this AA

Gas distributors presently have no direct responsibilities to customers, instead relying on retailers to provide a full suite of services to retail customers and to

[82] It appears that the RPWG intends that the 'gas service agreement' will be an access arrangement covering all matters between the retailer and distributor to do with the transportation of gas to supply points of retail customers.

contract with distributors for network transportation and all necessary ancillary services.

The NECF will require distributors to have legally enforceable responsibilities to customers, backed up by an uncapped liability for negligence. This arrangement is completely new, and its consequences, while unknown at this stage, could be very substantial. It appears likely that some functions (and therefore costs) previously borne by retailers will now be shifted to distributors. It may be necessary for distributors to establish separate call centres, or at least set up some kind of customer service facility.

Additionally, the NECF will mandate a number of contractual conditions, including liabilities, between retailers and distributors which were previously negotiated as part of the terms and conditions of retail access to distribution networks. Again, the consequences of these mandates are unknown.

It is clear that the MCE/SCO recognises that the NECF will shift existing industry cost patterns. The recent Regulatory Impact Statement (**RIS**) for the NECF says:

> The models available to SCO for adoption in the national framework each present liability regimes where the liabilities are transferred at the cost or benefit of the three parties. For example, where distributors benefit by not being included in a deemed contractual relationship, this is at the cost of retailers who may assume liability to customers in relation to faulty supply, for example, and prevents customers from seeking redress from the party in control of the service (as applicable). Where distributors have direct liability to customers, distributors may incur extra costs, but this can be expected to benefit energy customers and retailers.[83]

Conclusions from prospective NECF

Gas distributors will face new responsibilities which will create new, but presently unquantifiable, costs due to:

- new distributor customer responsibilities, involving additional transaction costs
- new distributor contractual liabilities towards customers and retailers, including civil penalties
- new distributor negligence liabilities applicable to customers and retailers

[83] Ministerial Council on Energy Standing Committee of Officials, *Regulation Impact Statement - A National Framework for Regulating Electricity and Gas (Energy) Distribution and Retail Services to Customers*, 16 July 2009, p. 74.

- new AER compliance, monitoring and enforcement powers which will require new systems and procedures to be implemented by distributors.

Therefore, JGN proposes passing through costs associated with changes to its AA resulting from the introduction of the NECF.

16.6.5 National gas connections framework

The MCE/SCO has signalled the development new national customer connection frameworks and policies and for both electricity and gas distributors. MCE/SCO has noted that[84]:

- in December 2008 the MCE/SCO released the policy paper outlining a proposed national framework for electricity distribution connection arrangements
- there is a degree of overlap or interaction of the connections procedures with the NECF
- the Network Policy Working Group (**NPWG**) work stream also includes the development of a national framework for gas connection arrangements
- work on the gas framework will follow the development of the national framework for electricity.

Judging by the earlier electricity consultation, it appears that connections policy will place an obligation on gas distributors to initiate network connections directly with customers, while allowing that, as an alternative, retailers or other intermediaries could be involved. If so, this would introduce a new model of direct service provision to customers, rather than as a service to users such as retailers.

Given that SCO has indicated that the connection frameworks will be integrated with the NECF, the same uncertainties apply as with the NECF:

- only a high level framework has so far been released for electricity, and nothing official for gas
- the NGR which will specify the obligations of distributors have yet to be developed in detail
- significant consultation on the NGCF will be required

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[84] Ministerial Council on Energy Standing Committee of Officials: *First Exposure Draft Law and Rules - Explanatory Memorandum*, 30 April 2009, p. 26.

- the timing of legislation to introduce the customer connection frameworks (including gas) is uncertain

- transitional arrangements have not been developed.

Therefore, JGN proposes passing through costs associated with changes to its AA resulting from the NGCF.

16.6.6 Australian Energy Market Operator

On 1 July 2009 a single, industry funded national energy market operator for both electricity and gas came into operation known as AEMO. A key part of the implementation of AEMO was to establish the regulatory framework, involving changes to the national electricity and gas laws and rules.

One of AEMO's functions is to replace the former Gas Market Company, which among other things administered the Gas Retail Market Rules and facilitated gas balancing for NSW and the ACT. These matters will now be dealt with, respectively, under AEMO gas retail market procedures and wholesale market procedures under the STTM. In addition AEMO will establish an annual Gas Market Statement of Opportunities.

For this AA, JGN has adjusted its contractual conditions for transportation services to better align with the initial AEMO procedures, particularly in regard to:

- ongoing contractual terms and conditions

- services to be offered by JGA set out in chapter 13

- charging structures for reference tariffs set out in chapter 14.

JGN issues

JGN is concerned that the introduction and amendment of AEMO legislative instruments may affect the operation of the AA.

Under s91M of the *National Gas (South Australia) (National Gas Law - Australian Energy Market Operator) Amendment Act 2009* (**Amendment Act**), the AEMO may, in accordance with the NGR, make retail market procedures

Section 91MB(1) of the Amendment Act makes it clear that each person to whom the AEMO procedures are applicable must comply with the procedures. JGN's access arrangement must therefore have to flexibility to deal with unanticipated costs arising from new procedures (as they will be new regulatory obligations).

In the past JGN's relationship with Gas Market Company (**GMC**) was such that the cost to JGN of additional requirements on JGN arising from market rule changes were dealt with by direct reimbursement of JGN's cost by the GMC. Under AEMO this arrangement will no longer be available. Accordingly JGN has made reasonable allowance in its capital forecast for IT system change requirements that are likely to arise. However new requirements on JGN are also likely to give rise to additional operating costs which have not been forecast. In this circumstance JGN proposes to recover these costs through tariffs on an annual pass through basis, including financing costs for any items not specifically identified in JGN's capex proposal.

16.6.7 Short term trading market

The STTM will facilitate settlement of wholesale gas sales to JGN's trunk and distribution assets servicing Sydney, Wollongong, Newcastle and the Central Coast, and will treat them as a single market hub. The STTM is scheduled to begin by July 2010.

The STTM will require some fundamental structural changes from the existing contract carriage model used in the defined NSW hub network section. Various terms and conditions of JGN's current AA will not be consistent with the network transportation structure anticipated by the STTM and will therefore need to be altered.

JGN's assessment of the likely revisions to its AA to accommodate the STTM is as follows. These matters are not exhaustive and are subject to further clarification of the proposed law, rules and procedures. JGN therefore proposes that its AA must have flexibility to respond to updated STTM legislation, and to provide for additional costs arising from that legislation.

The proposed changes to JGN's AA to accommodate the STTM are as follows:

Operational balancing

JGN expects that it will maintain existing contractual rights and systems to be able to balance the Wilton network section (**STTM NSW hub**). However, JGN anticipates that it will have the flexibility not to be bound to apply existing arrangements on the basis that JGN can adopt the STTM as an acceptable alternative balancing arrangement for the Wilton-Newcastle and Wilton-Wollongong balanced network section.

Title to gas and upstream obligations

JGN assumes that the STTM will provide users with legal title to gas at network receipt points for onward transportation by JGN, and that it will also provide users with the means to continue to meet other fundamental access obligations, such as upstream performance (e.g. gas quality) and to accept transfer of related network risks (e.g. non delivery of gas).

Therefore, JGN's terms and conditions will continue to place obligations on users concerning the right and title to gas at network receipt points and the various existing upstream obligations.

Obligations to deliver and receive gas by receipt point

Current obligations on users and JGN to deliver and receive (respectively) gas by receipt point are inconsistent with the design principles of the STTM as network receipts will be scheduled for users collectively rather than individually.

The STTM will not provide users with the means of controlling or accounting for which receipt point their gas is delivered to or from which receipt point that gas is transported. JGN proposes modifications to its price structure and terms and conditions to accommodate transportation to delivery points predicated on aggregate supply to the NSW hub.

16.6.8 Financial failure of a retailer

JGN obtains most of its revenue from users, mainly retailers. For the most part, these retailers must meet set creditworthiness standards, including:

- investment grade credit rating
- bank or parent company guarantee for three months worth of distribution charges.

Although these minimum standards help lower the risk of financial failure by the retailer, they cannot remove this risk completely. If a large retailer were to stop paying its bills without full credit support, then JGN would itself bear the very great cost of such a failure.

Because it can have no control over such failures, JGN proposes a pass through arrangement for the difference between:

- the credit support made available by a retailer that fails, such as a guarantee
- the amount of unpaid bills from that retailer.

16.6.9 Retailer of last resort event

If a retailer fails, then a ROLR event may also occur. This event may trigger pre-existing procedures that pass a cost onto JGN, including administrative costs from transferring the customers of a failed retailer to the retailer of last resort within a short time period.

These costs are largely outside of JGN's control. JGN proposes passing through any material incremental costs of a ROLR event which JGN cannot recover through another mechanism.

16.6.10 Business continuity

JGN manages its network to stay in business by maintaining assets and insuring against most business risks.

Some potential risks from events may affect JGN's business continuity, but are too expensive to insure fully, such as extreme weather events or major civil unrest. To fully cost these events into an AA may conflict with the efficiency intent of the NGO and the NGR.

JGN has assessed the following events as potentially affecting JGN but being too uncertain to forecast or too costly to insure fully:

- tsunami
- cyclone
- pandemic illness
- earthquake
- supply curtailment.

Therefore, JGN proposes passing through costs from events that affect its business continuity for which it is prohibitively expensive and potentially inefficient to fully insure, including but not limited to the above events.

16.7 RIN and rule 72 requirements

Table 16-2 sets out RIN requirements met in chapter 16. There are no rule 72 requirements relevant to chapter 16.

Table 16-2: RIN requirements

RIN reference	RIN requirement	Where addressed in AAI
Cost pass through mechanism		
2.5.4.2	In the access arrangement proposal submission (a) Clearly define and describe each cost pass through event	Section 16.6

RIN reference	RIN requirement	Where addressed in AAI
2.5.4.2	(b) Justify cost pass through mechanism and address the factors contained in Rule 97(3) Note: In doing so the service provider needs to establish a threshold level of costs to be passed through which considers the administrative costs of the AER, the service provider and users or potential users (Rule 97(3)(b)).	Section 16.6
2.5.4.2	(c) Explain how each cost pass through event is relevant to a building block component in Rule 76 and is uncontrollable and is not included in forecasts for total revenue.	Section 16.1, 16.6
2.5.4.2	(d) Explain how the cost pass through mechanism gives the AER adequate oversight or powers of approval over variation of the reference tariff (Rule 97(4)) Note: In order to address the requirements in Rule 97(4) and Rule 97(3) the service provider will need to outline the administrative arrangements) for cost-pass through events and their relationship to other periodic reviews for other tariff variation mechanisms (especially timing of notifications to the AER).	AA clauses 3.4 and 3.5

17 Terms and conditions

JGN's AA represents a transition of a policy form of AA to a more contractual form of AA. JGN intends this change to improve the administrative simplicity of its AA for users and customers and thereby better support the NGO.

This chapter discussed key changes in JGN's terms and conditions and is structured as follows:

- *Section 17.1 Changes to form of terms and conditions* – Discusses how the form of JGN's terms and conditions has been updated to reflect a contractual form of AA

- *Section 17.2 Changes to substance of terms and conditions* – Describes key changes to JGN's terms and conditions and the reasons for JGN's proposed changes.

17.1 Changes to form of terms and conditions

JGN's current AA contains a description of the minimum terms and conditions for access to the network. These are "policy based" and are interspersed throughout the AA as high level principles for the basis of contract negotiation.

This 2010 AA contains terms and conditions that act as a Reference Service Agreement to cater for all prospective users (supplying both small and large end consumers) where they are seeking reference services. The terms and conditions are in contractual form.

This change is designed to make the process of contracting with JGN more straight forward for both JGN and prospective users. JGN considers that the reduction in administrative burden associated with the new form of the terms and conditions and the enhanced certainty for JGN and users promotes the NGO.

This Reference Service Agreement format together with JGN's simplified reference service offerings provide greater consistency with gas networks in other Australian jurisdictions. This is consistent with the recommendations of the Ministerial Council on Energy's expert panel[85] and can be expected to better support the NGO than JGN's current AA.

[85] Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006.

17.2 Changes to substance of terms and conditions

While the essential elements of the terms of conditions in this AA are substantially the same as those in the current AA, there have been some changes made in response to market development and the changing nature of the gas distribution business.

Some of the more significant changes made to the terms and conditions are outlined below

17.2.1 Simplified reference services

As outlined in section 13.4, JGN's 2010-11 to 2014-15 AA contains the one haulage service which supersedes the following services from the current AA: tariff service, capacity reservation service, managed capacity service, throughput service, multiple delivery point service, gas swap service. This simplification of the reference services will aid administrative simplicity and reduce transaction costs.

17.2.2 Rolling contract term

There will no longer be a standard contract term as was previously provided for in the reference terms and conditions. The new terms and conditions provide that users may remain on the contract for reference services until they advise JGN otherwise (or the contract is amended or terminated in accordance with its terms).

17.2.3 Customer "churn"

Reduced administration for churn and capacity management for high-consumption delivery points: JGN will implement a "peak demand" approach to setting chargeable demand for capacity based services to large end-consumers. This will provide the following benefits to users:

- no exposure to retrospective overrun charges and an associated reduced requirement to monitor customer MDQ bookings
- addition and deletion of delivery points at the time of retail market churn based on existing user's delivery point characteristics (no requirement for incoming user to request a service separately from churn in market systems).

17.2.4 Transitional provisions

Transitional arrangements will allow users to move delivery points from their existing contracts to revised contracts for the new simplified reference services. The transitional provisions allow users to stay on old services unless they request to move to a new service.

17.2.5 Balancing

The 2005-10 AA has the same balancing schedule as the current AA. However, the terms and conditions make provision for this schedule to become obsolete when the STTM commences operation as balancing will then be replaced by STTM arrangements.

The terms and conditions include provision for balancing in the event that the STTM is suspended.

Glossary

AA	access arrangement
AAI	access arrangement information
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
AEMA	Australian Energy Market Agreement
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGL	Australian Gas Light Company
AGLGN	AGL Gas Networks Limited
AIC	average incremental cost
AMA	asset management agreement between JGN and JAM
AMP	asset management plan
APA	APA Group: the Australian Pipeline Trust and APT Investment Trust
A&O	administration and overheads
BASIX	Building Sustainability Index
BB	gas market bulletin board
BOM	Bureau of Meteorology
CEG	Competition Economists Group
capex	capital expenditure
CAPM	capital asset pricing model
CGS	Commonwealth government securities
CHOS	customer hours off supply
CLM Act	NSW Contaminated Land Management Act
COAG	Council of Australian Governments
CPI	consumer price index
CPRS	carbon pollution reduction scheme
COS	cost of service
current AA period	current access arrangement period: 1 July 2005 to 30 June 2010
customer	an end user of gas
DECC	Department of Environment and Climate Change
DMS	Data and Measurement Solutions

EBA	enterprise bargaining agreements
EBIT	earnings before interest and tax
EBS	Enterprise Business Services
EEH	energy efficient homes
EGP	Eastern Gas Pipeline
ENA	Energy Networks Association
ESF	enterprise support functions
E to G	electricity to gas hot water conversion
EUCS	energy use and conservation survey
FF	Fama-French three-factor model
Gas Supply Act	Gas Supply Act 1996 (NSW)
GCSS	guaranteed customer service level standards
GGAS	NSW Greenhouse Gas Reduction Scheme
GIS	geographic information system
GJ	gigajoule
GMC	Gas Market Company
GRMO	Queensland Gas Retail Market Operator
GSOO	Gas Market Statement of Opportunities
GSP	gross state product
HDD	heating degree days
ICB	initial capital base
IPART	Independent Pricing and Regulatory Tribunal of New South Wales
ISC	Implementation Steering Committee
IT	Information technology
ITP	IT Plan
JAM	Jemena Asset Management Pty Ltd (ACN 086 013 461)
JGN	Jemena Gas Networks (NSW) Limited, ACN 003 004 322
JGN network	controller and operator of gas distribution networks in NSW
KPI	key performance indicator
LFS	Labour Force Survey
LGA	local government area
LRMC	long run marginal cost
MAOP	maximum allowable operating pressure
MCE	Ministerial Council on Energy

MCE/SCO	Standing Committee of Officials that support the MCE
MDQ	maximum daily quantity
MEM	market expansion mechanism
MEPS	mandatory energy performance standards
MMA	McLennan Magasanik Associates
MRC	Marsh Risk Consulting
MRET	mandatory renewable energy target
MRP	market risk premium
MSP	Moomba to Sydney pipeline
NCC	National Competition Council
NECF	national energy customer framework
NEET	NSW Energy Efficiency Target scheme
NEMMCO	National Electricity Market Management Company Limited
NERL	National Energy Retail Law, proposed
NERR	National Energy Retail Rules, proposed
next AA period	next access arrangement period: 1 July 2010 to 30 June 2015
NGCF	national gas connections framework
NGER	national greenhouse and energy reporting
NGERAC	National Gas Emergency Response Advisory Committee
NGL	National Gas Law, schedule of the National Gas (South Australia) Act 2008
NGO	national gas objective
NGR	National Gas Rules
NIEIR	National Institute of Economic and Industry Research
NPV	net present value
NPWG	Network Policy Working Group
NSW	New South Wales
O&M	operating and maintenance expenditure
opex	operating expenditure
ORC	optimised replacement cost
PB	Parsons Brinckerhoff
Pipelines Act	Pipelines Act 1967 (NSW)
Pipelines Regulation	Pipelines Regulation 2005 (NSW)
previous AA period	previous access arrangement period: 1 July 2000 to 30 June 2005

PJ	petajoule (10^{15} joules)
POTS	packaged off-take station
PRS	primary receiving station
PTRM	post tax revenue model
PV	photovoltaic
PwC	PriceWaterhouseCoopers
RAB	regulatory asset base
RBA	Reserve Bank of Australia
RBSM	risk and benefit sharing mechanism
REC	renewable energy certificate
REMCo	South Australian Retail Energy Market Company
RET	renewable energy target
RFP	request for proposal
RIN	regulatory information notice under national gas rule 48(1)
RIS	Regulatory Impact Statement
ROLR	retailer of last resort
RPWG	Retail Policy Working Group
RSA	Reference Service Agreement
RSC	retail support clause
SAIDI	system average interruption duration index
SGC	Sydney Gas Company
SMP	Service Model Project
SPIAA	SPI (Australia) Assets Pty Ltd
SPM	service performance measure
STTM	short term trading market
subsequent AA period	subsequent access arrangement period: 1 July 2015 to 30 June 2020
t CO2e	tonnes of equivalent carbon dioxide
TJ	terajoule (10^{12} joules)
UAG	unaccounted for gas
user	a party who contracts with JGN for its use of JGN's pipeline services
VENCorp	Victorian Energy Networks Corporation
WAPC	weighted average price cap

WACC	weighted average cost of capital
WBS	work breakdown structure
WELS	water efficiency labelling and standards
WOBCA	whole of business cost allocation

List of appendices

Appendix	
Appendix 1.1: Access Arrangement changes	
Appendix 1.2: Regulatory information notice compliance checklist	
Appendix 3.4: Pitcher Partners probity review report	
Appendix 5.1: Gas market environment	
Appendix 5.2: NIEIR demand forecasts	
Appendix 6.3: Step changes	
Appendix 6.4: CEG cost escalator expert report	
Appendix 6.7: Economic Insights TFP report	
Appendix 7.3: Capex categorisations	
Appendix 7.4: PB expert review of AMP capex	
Appendix 9.1: NERA report on cost of equity	
Appendix 9.2: Joint DB AMI submission on debt risk premium	
Appendix 9.3: Effective tax rate calculations	
Appendix 15.3: Stand alone avoidable cost	
Appendix 15.4: Long run marginal cost	